Isaac M. Pachulski (CA Bar No. 62337)
Debra I. Grassgreen (CA Bar No. 169978)
PACHULSKI STANG ZIEHL & JONES LLP
1 Sansome Street, Suite 3430
San Francisco, CA 94104
Telephone: (415) 263-7000
Facsimile: (415) 263-7010
Email: dgrassgreen@pszjlaw.com

Eric Seiler (admitted *pro hac vice*)
Jason C. Rubinstein (admitted *pro hac vice*)
Michael S. Palmieri (admitted *pro hac vice*)
Matthew Tharp (*pro hac vice* pending)
FRIEDMAN KAPLAN SEILER ADELMAN AND ROBBINS LLP
7 Times Square
New York, NY 10036-6516
Telephone (212) 833-1103
Facsimile (212) 373-7903
Email: eseiler@fklaw.com

Attorneys for Securities Claimant
Baupost Group Securities, L.L.C

UNITED STATES BANKRUPTCY COURT
NORTHERN DISTRICT OF CALIFORNIA
SAN FRANCISCO DIVISION

In re: PG&E CORPORATION, -and- PACIFIC GAS AND ELECTRIC COMPANY, Debtors. ☐ Affects PG&E Corporation ☐ Affects Pacific Gas and Electric Company ☒ Affects both Debtors * *All papers shall be filed in the lead case, NO. 19-30088 (DM)*	Chapter 11 Bankr. Case No. 19-30088 (DM) (Jointly Administered) **REQUEST FOR JUDICIAL NOTICE IN SUPPORT OF THE OPPOSITION OF BAUPOST GROUP SECURITIES, L.L.C. TO THE REORGANIZED DEBTORS' THIRTY-FIFTH SECURITIES CLAIMS OMNIBUS OBJECTION TO THE BAUPOST AMENDMENT**

Pursuant to Federal Rule of Evidence 201, applicable in these proceedings pursuant to Federal Rule of Bankruptcy Procedure 9017, Securities Claimant Baupost Group Securities, L.L.C. ("**Baupost**"), by and through its attorneys, requests that the Court take judicial notice of the nine exhibits attached hereto as Exhibits A-I and listed below (the "**Exhibits**"). The Exhibits are submitted in support of the *Opposition of Baupost Group Securities, L.L.C. to the Reorganized Debtors' Thirty-Fifth Securities Claims Omnibus Objection to the Baupost Amendment*, filed March 15, 2024 (the "**Baupost Opposition**").[1]

In its *Omnibus Request for Incorporation of Documents By Reference or Judicial Notice In Support of Reorganized Debtors' Thirty-Third, Thirty-Fourth, and Thirty-Fifth Securities Claims Omnibus Objections* (Dkt. No. 14208) ("**PG&E's RJN**") and in its Objections, PG&E asks the Court to take judicial notice of *disputed facts* to resolve *disputed questions of fact*. For the reasons stated in the Baupost Opposition, this is improper—including because the Objections are addressed to the legal, not factual, sufficiency of Baupost's proofs of claims and because there has been no discovery in connection with this contested matter. *See* Bau. Obj. at 25-26; *see also Aldave v. City of Buena Park*, 2021 WL 4539741, at *2 (C.D. Cal. July 7, 2021) ("[A] court cannot take judicial notice of disputed facts.").

By contrast, Baupost's requests for judicial notice either (i) relate to *undisputed* "matters of which a court may take judicial notice," *see, e.g.*, *Tellabs, Inc. v. Makor Issues & Rts., Ltd.*, 551 U.S. 308, 322 (2007); or (ii) demonstrate the existence of factual issues sufficient to rebut PG&E's assertions that it is entitled to have Baupost's claims disallowed as a matter of law. Unlike PG&E, Baupost is *not* asking the Court to take judicial notice of documents outside the pleadings to resolve disputed questions of fact.

EXHIBIT	DESCRIPTION	BASIS FOR JUDICIAL NOTICE
A	Baupost's Rescission or Damage Claim Proofs of Claim, submitted in these proceedings as Claim Nos. 100269 and 100309 on or around April 15, 2020	Judicial Document

[1] Capitalized terms not otherwise defined herein shall have the meanings ascribed to them in the Baupost Opposition.

EXHIBIT	DESCRIPTION	BASIS FOR JUDICIAL NOTICE
B	Excerpt of PG&E webpage titled "Transmission vs. distribution power lines" available at: https://web.archive.org/web/20231104201504/https://www.pge.com/en_US/safety/yard-safety/powerlines-and-trees/transmission-vs-distribution-power-lines.page	PG&E's Public Webpage
C	Study of Risk Assessment and PG&E's GRC Report, submitted to the CPUC by Liberty Consulting Group on or around May 17, 2013	Regulatory Materials
D	Excerpts from transcript of testimony of David Gabbard in Confidential Grand Jury Proceedings, BCSC-2019-GJ-001, in the Superior Court of the State of California (Butte County), dated February 25, 2020	Judicial Document
E	January 24, 2019 Cal Fire News Release titled "CAL Fire Investigators Determine the Cause of the Tubbs Fire"	Regulatory Materials
F	January 24, 2024 transcript of hearing in *In re PG&E Corporation and Pacific Gas and Electric Company* (Bankr. N.D. Cal.)	Judicial Document
G	Consolidated Second Amended Class Action Complaint for Violation of Federal Securities Laws, filed in *Barnes v. Edison Int'l,* 18-cv-9690 (C.D. Cal.) [Dkt. No. 121]	Judicial Document
H	October 12, 2017 Letter from the CPUC to PG&E	Regulatory Materials
I	Excerpts from a November 30, 2017 Risk Assessment and Mitigation Phase Report, submitted by PG&E to the CPUC	Regulatory Materials

I. LEGAL STANDARD

Under Rule 201 of the Federal Rules of Evidence, courts may take judicial notice of any fact that is "not subject to reasonable dispute because it: (1) is generally known within the trial court's territorial jurisdiction; or (2) can be accurately and readily determined from sources whose accuracy cannot reasonably be questioned." Fed. R. Evid. 201(b).

II. ARGUMENT

For the following reasons, the Court may take judicial notice of each of the attached Exhibits.

A. <u>Judicial Documents</u>

It is well established that the Court may take judicial notice of court filings and other judicial materials under Rule 201. *See United States v. Black*, 482 F.3d 1035, 1041 (9th Cir. 2007) ("[Courts] may take notice of proceedings in other courts, both within and without the federal

judicial system, if those proceedings have a direct relation to matters at issue."); *In re Heller Ehrman LLP*, No. AP 23-03036, 2024 WL 922856, at *3 (Bankr. N.D. Cal. Mar. 4, 2024) ("[T]his court can and will take judicial notice of relevant documents . . . on its docket.") (Montali, J.); *In re Sandri*, 501 B.R. 369, 371 (Bankr. N.D. Cal. 2013) ("[U]nder Federal Rule of Evidence 201, the court may take judicial notice of matters of public record.") (Montali, J.).

Here, Exhibits A, D, F, and G consist of relevant court filings, including: (i) a transcript of a hearing in these proceedings (Ex. F); (ii) one of Baupost's proofs of claim submitted in these proceedings (Ex. A); (iii) a complaint filed in a federal court action that, PG&E contends, is relevant to its Objections (Ex. G); and (iv) excerpts from the transcript of a PG&E executive's testimony before the grand jury convened by the Butte County District Attorney's Office in connection with its investigation into the Camp Fire (Ex. D). These documents are relevant to these proceedings and the Court may take judicial notice of them.

B. <u>Regulatory Materials</u>

The Court may also take judicial notice of publicly-available regulatory materials, including submissions to regulatory agencies. *See Ariz. Libertarian Party v. Reagan*, 798 F.3d 723, 727 n.3 (9th Cir. 2015) ("We may take judicial notice of 'official information posted on a governmental website, the accuracy of which is undisputed.'"); *In re Brugnara Properties VI*, 606 B.R. 371, 375 (Bankr. N.D. Cal. 2019) (taking judicial notice of "documents recorded with the San Francisco Office of the Assessor-Recorder [that were] publicly available") (Montali, J.).

Here, Baupost requests that the Court take judicial notice of Exhibits C, E, H, and I. These Exhibits consist of: (i) a publicly-available report submitted to the Safety and Enforcement Division of the CPUC by an independent consultant that reviewed PG&E's general rate case filing (Ex. C); (ii) a Cal Fire news release concerning its investigation into one of the North Bay Fires (Ex. E); (iii) a publicly-available letter from the CPUC to PG&E ordering it to preserve evidence after the North Bay Fires (Ex. H); and (iv) excerpts from a publicly-available risk assessment report that PG&E submitted to the CPUC (Ex. I). The Court may take judicial notice of these documents.

C. <u>PG&E's Website</u>

Baupost also seeks judicial notice of Exhibit B, which consists of archived pages from PG&E's website concerning its transmission and distribution lines and vegetation clearance requirements. The Court may take judicial notice of the content of public websites, particularly the contents of a party's website. *See Arroyo v. IA Lodging Santa Clara, LLC*, 2021 WL 2826707, at *2 (N.D. Cal. July 7, 2021) ("Public records and documents on publicly available websites are proper subjects of judicial notice.") (collecting cases); *Brown v. Google LLC*, 525 F. Supp. 3d 1049, 1061 (N.D. Cal. 2021) ("Courts have taken judicial notice of the contents of web pages available through the Wayback Machine as facts that can be accurately and readily determined from sources whose accuracy cannot reasonably be questioned."); *Granlund v. Burbank Hill Cmty. Ass'n*, 2020 WL 5498075, at *4 (C.D. Cal. Aug. 5, 2020) ("Courts have found it proper to take judicial notice of a party's own website pursuant to Fed. R. Evid. 201."); *Waterman v. Wells Fargo & Co.*, 2018 WL 287171, at *3 (C.D. Cal. Jan. 4, 2018) ("[D]ocuments that are available on a party's own website . . . are the proper subject of judicial notice.").

III. CONCLUSION

Baupost respectfully requests that the Court take judicial notice of the Exhibits when considering the Baupost Opposition.

Dated: March 15, 2024

PACHULSKI STANG ZIEHL & JONES LLP

/s/ Debra I. Grassgreen

Isaac M. Pachulski
Debra I. Grassgreen

\- and -

Eric Seiler (admitted *pro hac vice*)
Jason C. Rubinstein (admitted *pro hac vice*)
Michael S. Palmieri (admitted *pro hac vice*)
Matthew Tharp (*pro hac vice* pending)
FRIEDMAN KAPLAN SEILER
ADELMAN & ROBBINS LLP

Attorneys for Securities Claimant
Baupost Group Securities, L.L.C.

EXHIBIT A

United States Bankruptcy Court, Northern District of California

Fill in this information to identify the case (Select only one Debtor per claim form):

☒ PG&E Corporation (19-30088)

☐ Pacific Gas and Electric Company (19-30089)

Rescission or Damage Claim Proof of Claim

This form is for purchasers of the Debtors' publicly traded debt and/or equity securities listed on Annex A during the period from April 29, 2015 through November 15, 2018, inclusive, who are asserting claims against the Debtors for rescission or damages under the securities laws and Section 510(b) of the Bankruptcy Code. Read the instructions before filing this Rescission or Damage Claim Proof of Claim Form.

THIS FORM IS TO BE USED ONLY FOR CLAIMANTS THAT PURCHASED OR ACQUIRED THE DEBTORS' PUBLICLY TRADED DEBT AND/OR EQUITY SECURITIES LISTED ON ANNEX A FROM APRIL 29, 2015 THROUGH NOVEMBER 15, 2018 TO ASSERT CLAIMS FOR RESCISSION OR DAMAGES UNDER THE SECURITIES LAWS AND SECTION 510(b) OF THE BANKRUPTCY CODE AND NOT ANY OTHER CLAIMS.

DO NOT USE THIS FORM TO ASSERT A CLAIM IF YOU DID NOT PURCHASE OR ACQUIRE PUBLICLY TRADED DEBT OR EQUITY SECURITIES OF THE DEBTORS FROM APRIL 29, 2015 THROUGH NOVEMBER 15, 2018 AND YOUR CLAIM IS BASED SOLELY ON YOUR CURRENT AND CONTINUOUS OWNERSHIP OF SUCH SECURITIES.

Filers must leave out or partially redact SSNs/TINs/birthdates/names of minors/full account numbers. Attach redacted copies of any documents that support the claim. **Do not send original documents;** they may be destroyed after scanning. If the documents are not available, explain in an attachment.

A person who files a fraudulent claim could be fined up to $500,000, imprisoned for up to 5 years, or both. 18 U.S.C. §§ 152, 157, and 3571.

Fill in all the information about the claim as of January 29, 2019, the date these Chapter 11 Cases were filed. For purposes of this form, "creditor" means the beneficial owner of the securities that form the basis of the claim.

Part 1: Identify the Claim

1. **Who is the current creditor?**	Baupost Group Securities, L.L.C. (See Addendum.) Name of the current creditor (the person or entity to be paid for this claim) Other names the creditor used with the Debtor ______
2. **Has this claim been acquired from someone else?**	☒ No ☐ Yes. From whom? ______
3. **Are you asserting a Claim for rescission or damages under the securities laws and Section 510(b) of the Bankruptcy Code?**	**Check the box below to indicate whether you are asserting a claim for rescission or damages under the securities laws and section 510(b) of the Bankruptcy Code, arising from the purchase and/or acquisition of the Debtors' publicly traded debt and/or equity securities during the period from April 29, 2015 through November 15, 2018. You are directed to check only one box below:** ☐ Debt Securities; ☒ Equity Securities; or ☐ Debt Securities and Equity Securities **Please also check all applicable CUSIP(s) on Annex A, Part I (attached hereto) for the equity or debt securities to which this Proof of Claim applies (hereinafter "the Securities"). If you purchased/acquired multiple CUSIPs, you must make additional copies of Annex A, Part II, so that you submit a separate corresponding Annex A, Part II for each CUSIP, with the requested documentation.** **In addition to completing this Rescission or Damage Claim Proof of Claim Form, including checking the appropriate boxes on Annex A, Part I and providing the detail in Annex A, Part II, you are also required to attach to this Rescission or Damage Claim Proof of Claim Form any applicable detail regarding your purchases/acquisition of the securities from April 29, 2015 through November 15, 2018.** **Once you have completed Annex A, Part I and Part II, please affix them to this Rescission or Damage Claim Proof of Claim Form. If you are submitting your Proof of Claim electronically, you will be asked to scan all Annex A, Part I and Part II and supporting documentation. If you have numerous transactions to report in Annex A, Part II, Claimants with more than 100 transactions in the Debtors' securities may contact Prime Clerk for instructions on how to file their claims electronically.**

4. **Where should notices and payments to the creditor be sent?** Federal Rule of Bankruptcy Procedure (FRBP) 2002(g)	**Where should notices to the creditor be sent?** The Baupost Group, L.L.C. 10 St. James Avenue, 17th Fl Boston, MA 02116 Attn: Frederick H. Fogel Contact phone (617) 210-8300 Contact email pcgpublicteam@baupost.com	**Where should payments to the creditor be sent?** (if different) *As separately directed by the creditor Contact phone ______ Contact email ______
5. **Does this claim amend one already filed?**	☒ No ☐ Yes. Claim number on court claims registry (if known)______ Filed on ______ MM / DD / YYYY	
6. **Do you know if anyone else has filed a proof of claim for this claim?**	☒ No ☐ Yes. Who made the earlier filing? ______	

Part 2: Give Information About the Claim as of January 29, 2019

7. **Do you have any number you use to identify the debtor?**	☒ No ☐ Yes. Last 4 digits of the debtor's account or any number you use to identify the debtor: ___ ___ ___ ___
8. **How much is the claim?**	$To be determined. **Does this amount include interest or other charges?** ☒ No ☐ Yes. Attach statement itemizing interest, fees, expenses, or other charges required by Bankruptcy Rule 3001(c)(2)(A).
9. **Is all or part of the claim secured?**	☒ No ☐ Yes. The claim is secured by a lien on property. **Nature of property:** ☐ Real estate. If the claim is secured by the debtor's principal residence, file a *Mortgage Proof of Claim Attachment* (Official Form 410-A) with this *Proof of Claim.* ☐ Motor vehicle ☐ Other. Describe: ______ **Basis for perfection:** ______ Attach redacted copies of documents, if any, that show evidence of perfection of a security interest (for example, a mortgage, lien, certificate of title, financing statement, or other document that shows the lien has been filed or recorded.) **Value of property**: $______ **Amount of the claim that is secured:** $______ **Amount of the claim that is unsecured:** $______(The sum of the secured and unsecured amounts should match the amount in line 7.) **Amount necessary to cure any default as of the date of the petition:** $______ **Annual Interest Rate** (when case was filed)______% ☐ Fixed ☐ Variable
10. **Is this claim subject to a right of setoff?**	☒ No ☐ Yes. Identify the property: ______

Part 3: Sign Below

The person completing this proof of claim must sign and date it. FRBP 9011(b).

If you file this claim electronically, FRBP 5005(a)(2) authorizes courts to establish local rules specifying what a signature is.

A person who files a fraudulent claim could be fined up to $500,000, imprisoned for up to 5 years, or both. 18 U.S.C. §§ 152, 157, and 3571.

Check the appropriate box:

- ☒ I am the creditor.
- ☐ I am the creditor's attorney or authorized agent.
- ☐ I am the trustee, or the debtor, or their authorized agent. Bankruptcy Rule 3004.
- ☐ I am a guarantor, surety, endorser, or other codebtor. Bankruptcy Rule 3005.

I understand that an authorized signature on this *Proof of Claim* serves as an acknowledgment that when calculating the amount of the claim, the creditor gave the debtor credit for any payments received toward the debt.

I have examined the information in this *Proof of Claim* and have a reasonable belief that the information is true and correct.

I declare under penalty of perjury that the foregoing is true and correct.

Signature: Joshua A.S. Greenhill
Joshua A.S. Greenhill (Apr 15, 2020)

Email: nova.alindogan@ropesgray.com

Signature

Print the name of the person who is completing and signing this claim:

Name: Joshua A.S. Greenhill
First name Middle name Last name

Title: Partner

Company: Baupost Group Securities, L.L.C.
Identify the corporate servicer as the company if the authorized agent is a servicer.

Address: 10 St. James Avenue, 17th Floor
Number Street

Boston MA 02116
City State ZIP Code

Contact phone: (617) 210-8300 Email: pcgpublicteam@baupost.com

Attach Supporting Documentation **Including Annex A** (available for download on https://restructuring.primeclerk.com/pge) (limited to a single PDF attachment that is less than 5 megabytes in size and under 100 pages):

☒ I have supporting documentation. (attach below)

☐ I do not have supporting documentation.

Attachment

PLEASE REVIEW YOUR PROOF OF CLAIM AND SUPPORTING DOCUMENTS AND REDACT ACCORDINGLY PRIOR TO UPLOADING THEM. PROOFS OF CLAIM AND ATTACHMENTS ARE PUBLIC DOCUMENTS THAT WILL BE AVAILABLE FOR ANYONE TO VIEW ONLINE.

IMPORTANT NOTE REGARDING REDACTING YOUR PROOF OF CLAIM AND SUPPORTING DOCUMENTATION When you submit a proof of claim and any supporting documentation you must show only the last four digits of any social-security, individual's tax-identification, or financial-account number, only the initials of a minor's name, and only the year of any person's date of birth. If the claim is based on the delivery of health care goods or services, limit the disclosure of the goods or services so as to avoid embarrassment or the disclosure of confidential health care information.

A document has been redacted when the person filing it has masked, edited out, or otherwise deleted, certain information. The responsibility for redacting personal data identifiers (as defined in Federal Rule of Bankruptcy Procedure 9037) rests solely with the party submitting the documentation and their counsel. Prime Clerk and the Clerk of the Court will not review any document for redaction or compliance with this Rule and you hereby release and agree to hold harmless Prime Clerk and the Clerk of the Court from the disclosure of any personal data identifiers included in your submission. In the event Prime Clerk or the Clerk of the Court discover that personal identifier data or information concerning a minor individual has been included in a pleading, Prime Clerk and the Clerk of the Court are authorized, in their sole discretion, to redact all such information from the text of the filing and make an entry indicating the correction.

Instructions for Rescission or Damage Claim Proof of Claim

These instructions and definitions generally explain the law. In certain circumstances, such as bankruptcy cases that debtors do not file voluntarily, exceptions to these general rules may apply. You should consider obtaining the advice of an attorney, especially if you are unfamiliar with the bankruptcy process and privacy regulations.

A person who files a fraudulent claim could be fined up to $500,000, imprisoned for up to 5 years, or both. 18 U.S.C. §§ 152, 157 and 3571.

How to fill out this form

- **Fill in all of the information about any claim you may have based on your belief that you have suffered losses as a result of alleged inadequate or fraudulent disclosure or non-disclosure of information about the Debtors that may have led you to purchase or acquire publicly traded debt and/or equity securities during the period from April 29, 2015 through November 15, 2018, inclusive**
- **Fill in the caption at the top of the form.**
- **If the claim has been acquired from someone else, then state the identity of the last party** who owned the claim or was the holder of the claim and who transferred it to you before the initial claim was filed.
- **Complete Annex A, Part I by checking all applicable CUSIP(s) and provide the information requested in Annex A, Part II for that CUSIP. If you are asserting a claim based on more than one CUSIP, you must attach a separate Annex A, Part II for each CUSIP.**
- **Attach any supporting documents to this form.**

  Attach documentation requested in Annex A, Part II of the Form. (See the definition of *redaction* on the next page.)
- **Do not attach original documents because attachments may be destroyed after scanning.**
- **Leave out or redact confidential information both in the claim and in the attached documents.**
- **A *Proof of Claim* form and any attached documents must show only the last 4 digits of any social security number, individual's tax identification number, or financial account number, and only the year of any person's date of birth.** See Bankruptcy Rule 9037.
- **For a minor child, fill in only the child's initials and the full name and address of the child's parent or guardian.** For example, write *A.B., a minor child* (*John Doe, parent, 123 Main St., City, State*). See Bankruptcy Rule 9037.

Confirmation that the claim has been filed

To receive confirmation that the claim has been filed, enclose a stamped self-addressed envelope and a copy of this form. You may view a list of filed claims in this case by visiting the Claims and Noticing Agent's website at:
https://restructuring.primeclerk.com/pge.

Understand the terms used in this form

Claim: A creditor's right to receive payment for a debt that the debtor owed on the date the debtor filed for bankruptcy. 11 U.S.C. §101 (5). A claim may be secured or unsecured.

Creditor: A person, corporation, or other entity to whom a debtor owes a debt that was incurred on or before the date the debtor filed for bankruptcy. 11 U.S.C. §101 (10).

Debtor: A person, corporation, or other entity who is in bankruptcy. Use the debtor's name and case number as shown in the bankruptcy notice you received. 11 U.S.C. § 101 (13).

Evidence of perfection: Evidence of perfection of a security interest may include documents showing that a security interest has been filed or recorded, such as a mortgage, lien, certificate of title, or financing statement.

Information that is entitled to privacy: A *Proof of Claim* form and any attached documents must show only the last 4 digits of any social security number, an individual's tax identification number, or a financial account number, only the initials of a minor's name, and only the year of any person's date of birth. You may later be required to give more information if the trustee or someone else in interest objects to the claim.

Proof of claim: A form that shows the amount of debt the debtor owed to a creditor on the date of the bankruptcy filing. The form must be filed in the district where the case is pending.

Redaction of information: Masking, editing out, or deleting certain information to protect privacy. Filers must redact or leave out information entitled to **privacy** on the *Proof of Claim* form and any attached documents.

Secured claim under 11 U.S.C. §506(a): A claim backed by a lien on particular property of the debtor. A claim is secured to the extent that a creditor has the right to be paid from the property before other creditors are paid. The amount of a secured claim usually cannot be more than the value of the particular property on which the creditor has a lien. Any amount owed to a creditor that is more than the value of the property normally may be an unsecured claim. But exceptions exist; for example, see 11 U.S.C. § 1322(b) and the final sentence of 1325(a).

Examples of liens on property include a mortgage on real estate or a security interest in a car. A lien may be voluntarily granted by a debtor or may be obtained through a court proceeding. In some states, a court judgment may be a lien.

Setoff: Occurs when a creditor pays itself with money belonging to the debtor that it is holding, or by canceling a debt it owes to the debtor.

Unsecured claim: A claim that does not meet the requirements of a secured claim. A claim may be unsecured in part to the extent that the amount of the claim is more than the value of the property on which a creditor has a lien.

Offers to purchase a claim

Certain entities purchase claims for an amount that is less than the face value of the claims. These entities may contact creditors offering to purchase their claims. Some written communications from these entities may easily be confused with official court documentation or communications from the debtor. These entities do not represent the bankruptcy court, the bankruptcy trustee, or the debtor. A creditor has no obligation to sell its claim. However, if a creditor decides to sell its claim, any transfer of that claim is subject to Bankruptcy Rule 3001(e), any provisions of the Bankruptcy Code (11 U.S.C. § 101 et seq.) that apply, and any orders of the bankruptcy court that apply.

Please send completed Securities Proof(s) of Claim to:

If electronically:

Through the website established by the Debtors' Court-approved claims and noticing agent, Prime Clerk LLC ("**Prime Clerk**"), located at https://restructuring.primeclerk.com/pge (the "**Case Website**"), using the interface available under the linked entitled "Submit a Claim" (the "**Electronic Filing System**").

If by first class mail:

PG&E Corporation Claims Processing Center
c/o Prime Clerk LLC
Grand Central Station, PO Box 4850
New York, NY 10163-4850

If by overnight courier or hand delivery:

PG&E Corporation Claims Processing Center
c/o Prime Clerk LLC
850 Third Avenue, Suite 412
Brooklyn, NY 11232

Claimants with more than 100 transactions in the Debtors' securities may contact Prime Clerk for instructions on how to file their claims electronically.

Do not file these instructions with your form

IF SUBMITTING YOUR RESCISSION OR DAMAGE CLAIM PROOF OF CLAIM THROUGH PRIME CLERK'S ELECTRONIC PORTAL, THIS ANNEX (ALONG WITH ALL OTHER SUPPORTING DOCUMENTATION) WILL NEED TO BE SCANNED AND UPLOADED

Annex A

Part I

Check all relevant boxes below. If you purchased multiple CUSIPs, you must make additional copies of Part II.

Check One Box Below	Issuer of Securities	Securities Description	CUSIP Number	ISIN Number
☑	PG&E Corp	Common Stock (including any contract options related thereto)	69331C108	US69331C1080
☐	Pacific Gas & Electric Co	Preferred 4.36 PERP/CALL	694308883	US6943088830
☐	Pacific Gas & Electric Co	Preferred 4.5 PERP/CALL	694308800	US6943088004
☐	Pacific Gas & Electric Co	Preferred 4.8 PERP/CALL	694308701	US6943087014
☐	Pacific Gas & Electric Co	Preferred 5 PERP/CALL	694308503	US6943085034
☐	Pacific Gas & Electric Co	Preferred 5 PERP/CALL	694308602	US6943086024
☐	Pacific Gas & Electric Co	Preferred 5 PERPETUAL	694308404	US6943084045
☐	Pacific Gas & Electric Co	Preferred 5.5 PERPETUAL	694308305	US6943083054
☐	Pacific Gas & Electric Co	Preferred 6% Dividend PERPETUAL	694308206	US6943082064
☐	Pacific Gas & Electric Co	0.45835% due 5/11/2015	694308HJ9	US694308HJ92
☐	Pacific Gas & Electric Co	1.51778% due 11/30/2017	694308HQ3	US694308HQ36
☐	Pacific Gas & Electric Co	2.45% due 8/15/2022	694308HB6	US694308HB66
☐	Pacific Gas & Electric Co	2.54138% due 11/28/2018	694308HU4	US694308HU48
☐	Pacific Gas & Electric Co	2.54138% due 11/28/2018	694308HT7	US694308HT74
☐	Pacific Gas & Electric Co	2.54138% due 11/28/2018	U69430AD5	USU69430AD52
☐	Pacific Gas & Electric Co	2.95% due 3/1/2026	694308HP5	US694308HP52
☐	Pacific Gas & Electric Co	3.25% due 6/15/2023	694308HC4	US694308HC40
☐	Pacific Gas & Electric Co	3.25% due 9/15/2021	694308GW1	US694308GW13
☐	Pacific Gas & Electric Co	3.3% due 12/1/2027	694308HW0	US694308HW04
☐	Pacific Gas & Electric Co	3.3% due 12/1/2027	U69430AE3	USU69430AE36
☐	Pacific Gas & Electric Co	3.3% due 12/1/2027	694308HV2	US694308HV21
☐	Pacific Gas & Electric Co	3.3% due 3/15/2027	694308HS9	US694308HS91
☐	Pacific Gas & Electric Co	3.4% due 8/15/2024	694308HK6	US694308HK65
☐	Pacific Gas & Electric Co	3.5% due 10/1/2020	694308GT8	US694308GT83
☐	Pacific Gas & Electric Co	3.5% due 6/15/2025	694308HM2	US694308HM22
☐	Pacific Gas & Electric Co	3.75% due 2/15/2024	694308HG5	US694308HG53
☐	Pacific Gas & Electric Co	3.75% due 8/15/2042	694308HA8	US694308HA83
☐	Pacific Gas & Electric Co	3.85% due 11/15/2023	694308HE0	US694308HE06
☐	Pacific Gas & Electric Co	3.95% due 12/1/2047	694308HY6	US694308HY69
☐	Pacific Gas & Electric Co	3.95% due 12/1/2047	694308HX8	US694308HX86
☐	Pacific Gas & Electric Co	3.95% due 12/1/2047	U69430AF0	USU69430AF01
☐	Pacific Gas & Electric Co	4% due 12/1/2046	694308HR1	US694308HR19
☐	Pacific Gas & Electric Co	4.25% due 3/15/2046	694308HN0	US694308HN05
☐	Pacific Gas & Electric Co	4.25% due 5/15/2021	694308GV3	US694308GV30
☐	Pacific Gas & Electric Co	4.25% due 8/1/2023	694308HZ3	US694308HZ35
☐	Pacific Gas & Electric Co	4.25% due 8/1/2023	U69430AG8	USU69430AG83
☐	Pacific Gas & Electric Co	4.3% due 3/15/2045	694308HL4	US694308HL49
☐	Pacific Gas & Electric Co	4.45% due 4/15/2042	694308GZ4	US694308GZ44
☐	Pacific Gas & Electric Co	4.5% due 12/15/2041	694308GY7	US694308GY78
☐	Pacific Gas & Electric Co	4.6% due 6/15/2043	694308HD2	US694308HD23
☐	Pacific Gas & Electric Co	4.65% due 8/1/2028	694308JA6	US694308JA65
☐	Pacific Gas & Electric Co	4.65% due 8/1/2028	U69430AH6	USU69430AH66

IF SUBMITTING YOUR RECSISSION OR DAMAGE CLAIM PROOF OF CLAIM THROUGH PRIME CLERK'S ELECTRONIC PORTAL, THIS ANNEX (ALONG WITH ALL OTHER SUPPORTING DOCUMENTATION) WILL NEED TO BE SCANNED AND UPLOADED

Check One Box Below	Issuer of Securities	Securities Description	CUSIP Number	ISIN Number
☐	Pacific Gas & Electric Co	4.75% due 2/15/2044	694308HH3	US694308HH37
☐	Pacific Gas & Electric Co	5.125% due 11/15/2043	694308HF7	US694308HF70
☐	Pacific Gas & Electric Co	5.4% due 1/15/2040	694308GS0	US694308GS01
☐	Pacific Gas & Electric Co	5.625% due 11/30/2017	694308GL5	US694308GL57
☐	Pacific Gas & Electric Co	5.8% due 3/1/2037	694308GJ0	US694308GJ02
☐	Pacific Gas & Electric Co	5.8% due 3/1/2037	694308GK7	US694308GK74
☐	Pacific Gas & Electric Co	6.05% due 3/1/2034	694308GE1	US694308GE15
☐	Pacific Gas & Electric Co	6.05% due 3/1/2034	694308GH4	US694308GH46
☐	Pacific Gas & Electric Co	6.25% due 3/1/2039	694308GQ4	US694308GQ45
☐	Pacific Gas & Electric Co	6.35% due 2/15/2038	694308GM3	US694308GM31
☐	Pacific Gas & Electric Co	6.75% due 10/1/2023	694308EY9	US694308EY96
☐	Pacific Gas & Electric Co	6.75% due 10/1/2023	694308EZ6	US694308EZ61
☐	Pacific Gas & Electric Co	7.05% due 3/1/2024	694308FB8	US694308FB84
☐	Pacific Gas & Electric Co	7.05% due 3/1/2024	694308FP7	US694308FP70
☐	Pacific Gas & Electric Co	7.25% due 3/1/2026	694308EM5	US694308EM58
☐	Pacific Gas & Electric Co	7.25% due 3/1/2026	694308ET0	US694308ET02
☐	Pacific Gas & Electric Co	7.25% due 3/1/2026	694308FQ5	US694308FQ53
☐	Pacific Gas & Electric Co	7.25% due 3/1/2026	694308FY8	US694308FY87
☐	Pacific Gas & Electric Co	7.25% due 8/1/2026	694308EV5	US694308EV57
☐	Pacific Gas & Electric Co	7.25% due 8/1/2026	694308FF9	US694308FF98
☐	Pacific Gas & Electric Co	7.25% due 8/1/2026	694308EX1	US694308EX14
☐	Pacific Gas & Electric Co	7.25% due 8/1/2026	694308FR3	US694308FR37
☐	Pacific Gas & Electric Co	7.25% due 8/1/2026	694308FZ5	US694308FZ52
☐	Pacific Gas & Electric Co	8% due 10/1/2025	694308EP8	US694308EP89
☐	Pacific Gas & Electric Co	8% due 10/1/2025	694308EL7	US694308EL75
☐	Pacific Gas & Electric Co	8% due 10/1/2025	694308FM4	US694308FM40
☐	Pacific Gas & Electric Co	8% due 10/1/2025	694308FG7	US694308FG71
☐	Pacific Gas & Electric Co	8% due 10/1/2025	694308EK9	US694308EK92
☐	Pacific Gas & Electric Co	8.25% due 10/15/2018	694308GN1	US694308GN14
☐	Pacific Gas & Electric Co	8.25% due 11/1/2022	694308EQ6	US694308EQ62
☐	Pacific Gas & Electric Co	8.25% due 11/1/2022	694308EG8	US694308EG80
☐	Pacific Gas & Electric Co	8.25% due 11/1/2022	694308EN3	US694308EN32
☐	Pacific Gas & Electric Co	8.25% due 11/1/2022	694308FJ1	US694308FJ11
☐	Pacific Gas & Electric Co	8.25% due 11/1/2022	694308FW2	US694308FW22
☐	Pacific Gas & Electric Co	8.375% due 5/1/2025	694308EF0	US694308EF08
☐	Pacific Gas & Electric Co	8.375% due 5/1/2025	694308EJ2	US694308EJ20
☐	Pacific Gas & Electric Co	8.375% due 5/1/2025	694308FX0	US694308FX05
☐	Pacific Gas & Electric Co	8.8% due 5/1/2024	694308DV6	US694308DV66
☐	CA DEV VAR-A-PACIFIC	Municipal Bond ADJ% due 11/1/2026	13033WG31	
☐	CA DEV VAR-B-PACIFIC	Municipal Bond ADJ% due 11/1/2026	13033WG49	
☐	CA DEV VAR-C-PACIFIC	Municipal Bond due 12/1/2016	13033WG56	
☐	CA ECON-VAR-RF-3/14	Municipal Bond due 12/1/2018	13033WG23	
☐	CA ECON-VAR-RF-D-3/11	Municipal Bond due 12/1/2016	13033WF73	
☐	CA ECON-VAR-RF-E-3/11	Municipal Bond ADJ% due 11/1/2026	13033WF81	
☐	CA ECON-VAR-RF-F-3/12	Municipal Bond ADJ% due 11/1/2026	13033WF99	
☐	CA INFRA ECON DEV-F	Municipal Bond 1.75% due 11/1/2026	13034ASX9	US13034ASX99
☐	CA INFRA REF-GAS-F	Municipal Bond 3.75% due 11/1/2026	13033WU84	
☐	CA INFRA VAR-A-PACIFI	Municipal Bond ADJ% due 11/1/2026	13033WRZ8	

IF SUBMITTING YOUR RECSISSION OR DAMAGE CLAIM PROOF OF CLAIM THROUGH PRIME CLERK'S ELECTRONIC PORTAL, THIS ANNEX (ALONG WITH ALL OTHER SUPPORTING DOCUMENTATION) WILL NEED TO BE SCANNED AND UPLOADED

Check One Box Below	Issuer of Securities	Securities Description	CUSIP Number	ISIN Number
☐	CA INFRA VAR-B-PACIFI	Municipal Bond ADJ% due 11/1/2026	13033WSA2	
☐	CA INFRA VAR-C-PACIFI	Municipal Bond due 12/1/2016	13033WSB0	
☐	CA INFRA VAR-D-PACIFI	Municipal Bond due 12/1/2016	13033WSC8	
☐	CA INFRA VAR-E-PACIFI	Municipal Bond due 12/1/2016	13033WSD6	
☐	CA INFRA VAR-F-PACIFI	Municipal Bond ADJ% due 11/1/2026	13033WSE4	
☐	CA INFRA VAR-GAS-PACIFI	Municipal Bond due 12/1/2018	13033WU92	
☐	CA INFRA VAR-G-PACIFI	Municipal Bond due 12/1/2018	13033WSF1	
☐	CA INFRA VAR-PACIFIC	Municipal Bond ADJ% due 11/1/2026	13033WW33	
☐	CA INFRA VAR-PACIFIC	Municipal Bond due 12/1/2016	13033WW41	
☐	CA INFRA VAR-PACIFIC	Municipal Bond due 12/1/2016	13033WW58	
☐	CA INFRA VAR-REF-PACI	Municipal Bond ADJ% due 11/1/2026	13033WW25	
☐	CA INFRA-RF-C-PACIFIC	Municipal Bond due 12/1/2016	13033W3G6	
☐	CA INFRA-RF-D-PACIFIC	Municipal Bond due 12/1/2016	13033W3K7	
☐	CA INFRA-RF-E-PACIFIC	Municipal Bond 2.25% due 11/1/2026	13033W3Z4	
☐	CA INFRA-RF-VAR-A-PAC	Municipal Bond 3.75% due 11/1/2026	13033W3H4	US13033W3H41
☐	CA INFR-VR-RF-B-PACIF	Municipal Bond 3.75% due 11/1/2026	13033W3J0	US13033W3J07
☐	CA PCR DLY PAPER-PACI	Municipal Bond 4% due 11/1/2026	130534XA3	US130534XA35
☐	CA PCR DLY-PAC-E-CONV	Municipal Bond 3.5% due 11/1/2026	130534XX3	US130534XX38
☐	CA PCR DLY-REF-F-PACI	Municipal Bond 3.25% due 11/1/2026	130534XD7	US130534XD73
☐	CA PCR DLY-REF-G-PACI	Municipal Bond ADJ% due 2/1/2016	130534XE5	
☐	CA PCR VAR CAPCO MADR	Municipal Bond ADJ% due 9/1/2019	130535BA4	US130535BA48
☐	CA PCR VAR-REF-B-PACI	Municipal Bond 3.5% due 11/1/2026	130534XL9	US130534XL99
☐	CA PCR-REF-A-PAC	Municipal Bond 5.35% due 12/1/2016	130534WY2	
☐	CA POLLT-PAC GAS-REMK	Municipal Bond 4.75% due 12/1/2023	130534A83	
☐	CA POLLT-PAC GAS-REMK	Municipal Bond 4.75% due 12/1/2023	130534B66	
☐	CA POLLT-PAC GAS-REMK	Municipal Bond 4.75% due 12/1/2023	130534A91	
☐	CA POLLUTN-REF-A-PACI	Municipal Bond 3.5% due 12/1/2023	130534ZP8	
☐	CA POLLUTN-REF-B-PACI	Municipal Bond 3.5% due 12/1/2023	130534ZQ6	
☐	CA POLLUTN-REF-C-PACI	Municipal Bond 3.5% due 12/1/2023	130534ZR4	US130534ZR42
☐	CA POLLUTN-REF-D-PACI	Municipal Bond 3.5% due 12/1/2023	130534ZS2	
☐	CA POOLT-PAC GAS-REMK	Municipal Bond 4.75% due 12/1/2023	130534B25	
☐	CA POOLT-PCS GAS REMK	Municipal Bond 4.75% due 12/1/2023	130534B33	
☐	CALIFORNIA ST INFRAST	Municipal Bond 1.75% due 11/1/2026	13034ASZ4	US13034ASZ48
☐	NEVADA IRR YUBA PAC	Municipal Bond 3.75% due 7/1/2013	641321BT0	
☐	SOLANO IRR DIST DIV 1	Municipal Bond 9.15% due 1/1/2020	834125AN6	US834125AN62
☐	SOLANO IRR DIST DIV 2	Municipal Bond 9.25% due 1/1/2020	834125AM8	US834125AM89
☐	SOLANO IRR REF-MONTIC	Municipal Bond 5.47% due 1/1/2020	834125BC9	US834125BC98
☐	SOLANO IRR-REF-MONTIC	Municipal Bond 5.29% due 1/1/2016	834125AY2	
☐	SOLANO IRR-UNREF-#2	Municipal Bond 9.15% due 1/1/2020	834125BF2	
☐	SOLANO IRR-UNREF-#2	Municipal Bond 9.25% due 1/1/2020	834125BG0	US834125BG03

Annex A
Part II

CUSIP (Provide a Separate Tab for Each CUSIP):	69331C108	Beginning position held as of opening of trading on April 29, 2015 (if none, enter "0 shares" or "$0"):	0 shares	Ending position held as of the close of trading on November 15, 2018 (if none, enter "0 shares" or "$0"):	18,006,139 shares

Transaction Detail (Provide one row for each transaction for the above CUSIP between April 29, 2015 and November 15, 2018)

Purchase or Sale	Transaction Date (Purchase/Acquisition or Sale) (mm/dd/yyyy)	Number of Shares or Amount of Notes (in dollars)	Price per Share / Note	Total Cost (excluding Commissions, Taxes, and Fees)
Purchase	2/9/2018	17,500	$37.9117	$663,454.75
Purchase	2/9/2018	17,000	$37.8865	$644,070.50
Purchase	2/9/2018	101,700	$37.8050	$3,844,768.50
Purchase	2/9/2018	26,800	$37.9180	$1,016,202.40
Purchase	2/9/2018	35,300	$37.8471	$1,336,002.63
Purchase	2/9/2018	38,101	$37.9170	$1,444,675.62
Purchase	2/9/2018	207,921	$37.9011	$7,880,434.61
Purchase	2/9/2018	16,977	$37.8424	$642,450.42
Purchase	2/9/2018	11,100	$37.8919	$420,600.09
Purchase	2/12/2018	10,416	$38.4291	$400,277.51
Purchase	2/12/2018	1,000	$38.4340	$38,434.00
Purchase	2/12/2018	5,984	$38.4764	$230,242.78
Purchase	2/12/2018	4,800	$38.4322	$184,474.56
Purchase	2/12/2018	1,800	$38.4619	$69,231.42
Purchase	2/12/2018	1,100	$38.4682	$42,315.02
Purchase	2/12/2018	24,900	$38.5000	$958,650.00
Purchase	2/12/2018	100,000	$38.4850	$3,848,500.00
Purchase	2/20/2018	122,464	$39.9810	$4,896,233.18
Purchase	2/20/2018	366,700	$40.0812	$14,697,776.04
Purchase	2/20/2018	78,650	$39.8352	$3,133,038.48
Purchase	2/20/2018	25,300	$40.0318	$1,012,804.54
Purchase	2/20/2018	6,000	$39.8659	$239,195.40
Purchase	2/20/2018	14,600	$39.9055	$582,620.30
Purchase	2/20/2018	50,051	$39.9346	$1,998,766.66
Purchase	2/20/2018	2,500	$39.9234	$99,808.50
Purchase	2/21/2018	41,100	$40.3800	$1,659,618.00
Purchase	2/21/2018	268,500	$40.3538	$10,834,995.30
Purchase	2/21/2018	11,000	$40.3376	$443,713.60
Purchase	2/21/2018	32,700	$40.2296	$1,315,507.92
Purchase	2/21/2018	5,600	$40.0591	$224,330.96
Purchase	2/21/2018	5,500	$40.3777	$222,077.35
Purchase	2/21/2018	1,100	$40.3545	$44,389.95
Purchase	2/21/2018	600,000	$40.0410	$24,024,600.00

Annex A

Part II

Purchase or Sale	Transaction Date (Purchase/Acquisition or Sale) (mm/dd/yyyy)	Number of Shares or Amount of Notes (in dollars)	Price per Share / Note	Total Cost (excluding Commissions, Taxes, and Fees)
Purchase	2/22/2018	4,300	$40.1908	$172,820.44
Purchase	2/22/2018	375,000	$40.0906	$15,033,975.00
Purchase	2/22/2018	20,000	$39.9900	$799,800.00
Purchase	2/22/2018	16,400	$40.1235	$658,025.40
Purchase	2/22/2018	30,004	$40.0247	$1,200,901.10
Purchase	2/22/2018	10,422	$40.0793	$417,706.46
Purchase	2/22/2018	4,900	$40.0704	$196,344.96
Purchase	2/22/2018	3,410	$40.1018	$136,747.14
Purchase	2/22/2018	183,100	$39.9905	$7,322,260.55
Purchase	2/23/2018	2,600	$40.9481	$106,465.06
Purchase	2/23/2018	39,229	$40.8545	$1,602,681.18
Purchase	2/23/2018	18,400	$40.8000	$750,720.00
Purchase	2/23/2018	4,900	$40.5858	$198,870.42
Purchase	2/23/2018	30,371	$40.6648	$1,235,030.64
Purchase	2/23/2018	2,800	$40.9945	$114,784.60
Purchase	2/28/2018	1,242	$40.3275	$50,086.76
Purchase	2/28/2018	25,000	$40.2200	$1,005,500.00
Purchase	2/28/2018	340	$40.3750	$13,727.50
Purchase	2/28/2018	400	$40.4925	$16,197.00
Purchase	2/28/2018	300	$40.4933	$12,147.99
Purchase	2/28/2018	100	$40.4650	$4,046.50
Purchase	3/5/2018	119,300	$40.3696	$4,816,093.28
Purchase	3/5/2018	3,090	$40.4612	$125,025.11
Purchase	3/5/2018	100	$40.4800	$4,048.00
Purchase	3/5/2018	100	$40.4800	$4,048.00
Purchase	5/8/2018	100	$42.4950	$4,249.50
Purchase	5/8/2018	300	$42.4950	$12,748.50
Purchase	5/8/2018	1,000	$42.5000	$42,500.00
Purchase	5/9/2018	10,000	$42.4950	$424,950.00
Purchase	5/9/2018	4,200	$42.4746	$178,393.32
Purchase	5/9/2018	285,000	$42.4596	$12,100,986.00
Purchase	5/16/2018	397,016	$42.5000	$16,873,180.00
Purchase	5/16/2018	23,957	$42.4747	$1,017,566.39
Purchase	5/16/2018	4,755	$42.4911	$202,045.18
Purchase	5/16/2018	300	$42.4950	$12,748.50
Purchase	5/16/2018	19,100	$42.5000	$811,750.00
Purchase	5/16/2018	104,300	$42.4737	$4,430,006.91
Purchase	5/17/2018	266,000	$42.4500	$11,291,700.00

Annex A
Part II

Purchase or Sale	Transaction Date (Purchase/Acquisition or Sale) (mm/dd/yyyy)	Number of Shares or Amount of Notes (in dollars)	Price per Share / Note	Total Cost (excluding Commissions, Taxes, and Fees)
Purchase	5/17/2018	194,300	$42.2700	$8,213,061.00
Purchase	5/17/2018	1,016	$42.2151	$42,890.54
Purchase	5/17/2018	38,684	$42.3662	$1,638,894.08
Sale	7/3/2018	7,700	$44.2480	$340,709.60
Sale	7/3/2018	142,200	$44.0750	$6,267,465.00
Sale	7/3/2018	84,426	$44.2049	$3,732,042.89
Sale	7/3/2018	7,800	$44.0090	$343,270.20
Sale	7/5/2018	169,000	$43.9800	$7,432,620.00
Sale	7/5/2018	201,820	$43.9960	$8,879,272.72
Sale	7/5/2018	153,900	$43.7847	$6,738,465.33
Sale	7/5/2018	14,754	$43.9090	$647,833.39
Sale	7/5/2018	2,500	$43.8976	$109,744.00
Sale	7/5/2018	50,000	$44.1800	$2,209,000.00
Sale	7/5/2018	4,600	$44.0576	$202,664.96
Purchase	7/17/2018	838,700	$42.6709	$35,788,083.83
Purchase	7/25/2018	300,000	$42.8524	$12,855,720.00
Purchase	7/25/2018	13,056	$42.8078	$558,898.64
Purchase	7/25/2018	27,650	$42.6298	$1,178,713.97
Purchase	7/25/2018	2,600	$42.7412	$111,127.12
Purchase	7/25/2018	21,700	$42.6829	$926,218.93
Purchase	7/25/2018	60,981	$42.6064	$2,598,180.88
Purchase	7/25/2018	6,900	$42.7000	$294,630.00
Purchase	7/25/2018	12,700	$42.9698	$545,716.46
Purchase	7/26/2018	12,100	$42.9609	$519,826.89
Purchase	7/26/2018	900	$42.8939	$38,604.51
Purchase	7/26/2018	100	$42.8550	$4,285.50
Purchase	7/26/2018	8,962	$42.8866	$384,349.71
Purchase	7/26/2018	100	$42.9500	$4,295.00
Purchase	7/30/2018	32,600	$42.8776	$1,397,809.76
Purchase	7/30/2018	15,000	$42.9700	$644,550.00
Purchase	7/30/2018	23,808	$42.9320	$1,022,125.06
Purchase	7/30/2018	49,373	$42.9232	$2,119,247.15
Purchase	7/30/2018	6,000	$42.9260	$257,556.00
Purchase	7/30/2018	121,560	$42.9300	$5,218,570.80
Purchase	7/31/2018	1,000	$43.0000	$43,000.00
Purchase	7/31/2018	200	$42.9600	$8,592.00
Purchase	7/31/2018	300	$42.9500	$12,885.00
Purchase	7/31/2018	2,600	$42.9838	$111,757.88

Annex A
Part II

Purchase or Sale	Transaction Date (Purchase/Acquisition or Sale) (mm/dd/yyyy)	Number of Shares or Amount of Notes (in dollars)	Price per Share / Note	Total Cost (excluding Commissions, Taxes, and Fees)
Purchase	7/31/2018	83,000	$42.9535	$3,565,140.50
Purchase	7/31/2018	51,000	$42.9950	$2,192,745.00
Purchase	8/1/2018	32,100	$42.8381	$1,375,103.01
Purchase	8/1/2018	4,600	$42.4600	$195,316.00
Purchase	8/1/2018	39,115	$42.4115	$1,658,925.82
Purchase	8/1/2018	634,700	$42.3762	$26,896,174.14
Purchase	8/1/2018	1,000	$41.7300	$41,730.00
Purchase	8/1/2018	9,600	$42.3690	$406,742.40
Purchase	8/1/2018	16,816	$42.4446	$713,748.39
Purchase	8/1/2018	407,879	$42.2706	$17,241,290.06
Purchase	8/9/2018	37,565	$43.7422	$1,643,175.74
Purchase	8/9/2018	44,700	$43.7766	$1,956,814.02
Purchase	8/9/2018	2,700	$43.9037	$118,539.99
Purchase	8/9/2018	2,600	$43.7115	$113,649.90
Purchase	8/9/2018	238,778	$43.9137	$10,485,625.46
Purchase	8/9/2018	2,800	$43.9264	$122,993.92
Purchase	8/9/2018	180,000	$43.8409	$7,891,362.00
Purchase	8/10/2018	198,982	$42.9086	$8,538,039.05
Purchase	8/10/2018	1,445,000	$42.8881	$61,973,304.50
Purchase	8/10/2018	708,857	$42.7635	$30,313,206.32
Purchase	8/10/2018	19,600	$42.8650	$840,154.00
Purchase	8/10/2018	41,718	$42.8689	$1,788,404.77
Purchase	8/10/2018	63,100	$42.9899	$2,712,662.69
Purchase	8/10/2018	5,900	$42.9137	$253,190.83
Purchase	8/10/2018	7,700	$42.8551	$329,984.27
Purchase	8/13/2018	34,700	$42.7658	$1,483,973.26
Purchase	8/13/2018	662,369	$42.7431	$28,311,704.40
Purchase	8/13/2018	1,100	$42.7050	$46,975.50
Purchase	8/13/2018	8,900	$42.7566	$380,533.74
Purchase	8/13/2018	27,400	$42.7450	$1,171,213.00
Purchase	8/13/2018	839,700	$42.7466	$35,894,320.02
Purchase	8/14/2018	600,000	$42.9897	$25,793,820.00
Purchase	8/14/2018	118,300	$42.8474	$5,068,847.42
Purchase	8/14/2018	162,543	$42.9671	$6,984,001.34
Purchase	8/14/2018	76,382	$43.0154	$3,285,602.28
Purchase	8/14/2018	100,000	$42.8400	$4,284,000.00
Purchase	8/14/2018	46,175	$42.7826	$1,975,486.56
Purchase	8/14/2018	3,500	$42.9481	$150,318.35

Annex A
Part II

Purchase or Sale	Transaction Date (Purchase/Acquisition or Sale) (mm/dd/yyyy)	Number of Shares or Amount of Notes (in dollars)	Price per Share / Note	Total Cost (excluding Commissions, Taxes, and Fees)
Purchase	8/14/2018	500	$43.0000	$21,500.00
Purchase	8/14/2018	1,000	$43.0100	$43,010.00
Purchase	8/14/2018	300	$42.7900	$12,837.00
Purchase	8/15/2018	1,100	$43.4123	$47,753.53
Purchase	8/15/2018	33,000	$43.4517	$1,433,906.10
Purchase	8/15/2018	200	$43.4000	$8,680.00
Purchase	8/15/2018	45,500	$43.4415	$1,976,588.25
Purchase	8/15/2018	25,000	$43.3200	$1,083,000.00
Purchase	8/15/2018	26,600	$43.2966	$1,151,689.56
Purchase	8/15/2018	57,900	$43.3986	$2,512,778.94
Purchase	8/15/2018	49,087	$43.2102	$2,121,059.09
Purchase	8/20/2018	1,201,300	$43.9795	$52,832,573.35
Purchase	8/22/2018	34,500	$44.4085	$1,532,093.25
Purchase	8/22/2018	14,600	$44.4357	$648,761.22
Purchase	8/22/2018	15,100	$44.4313	$670,912.63
Purchase	8/22/2018	4,200	$44.4702	$186,774.84
Purchase	8/22/2018	4,100	$44.4213	$182,127.33
Purchase	8/23/2018	232,357	$44.1269	$10,253,194.10
Purchase	8/23/2018	489,424	$44.1819	$21,623,682.23
Purchase	8/23/2018	39,500	$44.0576	$1,740,275.20
Purchase	8/23/2018	51,500	$44.0297	$2,267,529.55
Purchase	8/23/2018	100,000	$43.9500	$4,395,000.00
Purchase	8/23/2018	5,300	$43.9696	$233,038.88
Purchase	8/23/2018	400	$43.9600	$17,584.00
Purchase	8/23/2018	17,500	$44.4950	$778,662.50
Purchase	8/24/2018	22,800	$42.8050	$975,954.00
Purchase	8/24/2018	650,000	$42.8489	$27,851,785.00
Purchase	8/24/2018	56,700	$42.7950	$2,426,476.50
Purchase	8/24/2018	1,000	$42.7600	$42,760.00
Purchase	8/24/2018	400	$42.7600	$17,104.00
Purchase	8/24/2018	13,300	$42.7914	$569,125.62
Purchase	8/24/2018	280,000	$43.3035	$12,124,980.00
Purchase	8/24/2018	83,400	$43.6010	$3,636,323.40
Purchase	8/24/2018	5,563	$43.1770	$240,193.65
Purchase	8/27/2018	2,700	$43.6967	$117,981.09
Purchase	8/27/2018	32,900	$43.6478	$1,436,012.62
Purchase	8/27/2018	95,172	$43.6912	$4,158,178.89
Purchase	8/27/2018	22,400	$43.2526	$968,858.24

Annex A
Part II

Purchase or Sale	Transaction Date (Purchase/Acquisition or Sale) (mm/dd/yyyy)	Number of Shares or Amount of Notes (in dollars)	Price per Share / Note	Total Cost (excluding Commissions, Taxes, and Fees)
Purchase	8/27/2018	36,500	$43.6182	$1,592,064.30
Purchase	8/27/2018	44,700	$43.5435	$1,946,394.45
Purchase	8/27/2018	54,628	$43.5968	$2,381,605.99
Purchase	8/27/2018	21,988	$43.2497	$950,974.40
Purchase	8/27/2018	192,500	$43.6442	$8,401,508.50
Purchase	8/28/2018	145	$44.4950	$6,451.78
Purchase	8/28/2018	2,400	$44.4950	$106,788.00
Purchase	8/28/2018	10,800	$44.5000	$480,600.00
Purchase	8/28/2018	2,200	$44.4555	$97,802.10
Purchase	8/28/2018	19,900	$44.5000	$885,550.00
Purchase	9/7/2018	300	$45.6900	$13,707.00
Purchase	9/7/2018	200	$45.6800	$9,136.00
Purchase	9/7/2018	95,571	$45.6784	$4,365,530.37
Purchase	9/7/2018	82,693	$45.5665	$3,768,030.58
Purchase	9/7/2018	17,800	$45.6831	$813,159.18
Purchase	9/7/2018	60,100	$45.6605	$2,744,196.05
Purchase	9/7/2018	103,500	$45.2300	$4,681,305.00
Purchase	9/18/2018	200,000	$47.1870	$9,437,400.00
Purchase	9/18/2018	400	$47.1488	$18,859.52
Purchase	9/18/2018	15,131	$47.1285	$713,101.33
Purchase	9/19/2018	9,400	$46.7904	$439,829.76
Purchase	9/19/2018	3,400	$46.7491	$158,946.94
Purchase	9/19/2018	2,400	$46.7746	$112,259.04
Purchase	9/19/2018	49,700	$46.6616	$2,319,081.52
Purchase	9/19/2018	47,375	$46.6608	$2,210,555.40
Purchase	9/19/2018	120,600	$46.7784	$5,641,475.04
Purchase	9/19/2018	852,105	$46.8542	$39,924,698.09
Purchase	9/19/2018	153,294	$46.6849	$7,156,515.06
Purchase	9/20/2018	200	$46.8150	$9,363.00
Purchase	9/20/2018	400	$46.7225	$18,689.00
Purchase	9/20/2018	867	$46.7335	$40,517.94
Purchase	9/20/2018	1,650	$46.8592	$77,317.68
Purchase	9/20/2018	543,078	$46.8308	$25,432,777.20
Sale	9/21/2018	275,334	$46.9075	$12,915,229.61
Purchase	9/26/2018	48,800	$45.3738	$2,214,241.44
Purchase	9/26/2018	15,236	$45.2951	$690,116.14
Purchase	9/26/2018	25,000	$45.1600	$1,129,000.00
Purchase	9/26/2018	12,800	$45.2133	$578,730.24

Annex A
Part II

Purchase or Sale	Transaction Date (Purchase/Acquisition or Sale) (mm/dd/yyyy)	Number of Shares or Amount of Notes (in dollars)	Price per Share / Note	Total Cost (excluding Commissions, Taxes, and Fees)
Purchase	9/26/2018	5,700	$45.2094	$257,693.58
Purchase	9/26/2018	900	$45.3000	$40,770.00
Purchase	9/26/2018	23,600	$45.2750	$1,068,490.00
Purchase	9/27/2018	453,900	$45.1810	$20,507,655.90
Purchase	9/28/2018	25,891	$45.6964	$1,183,125.49
Purchase	10/1/2018	400	$45.4400	$18,176.00
Purchase	10/1/2018	51,100	$45.4612	$2,323,067.32
Purchase	10/1/2018	2,500	$45.5076	$113,769.00
Purchase	10/1/2018	131,404	$45.5872	$5,990,340.43
Purchase	10/1/2018	2,400	$45.5667	$109,360.08
Sale	11/15/2018	426,085	$21.4249	$9,128,840.90
Sale	11/15/2018	71,100	$20.5526	$1,461,291.50
Sale	11/15/2018	286,770	$20.5797	$5,901,638.14
Sale	11/15/2018	115,400	$20.3935	$2,353,405.50
Sale	11/15/2018	12,600	$20.1798	$254,265.00
Sale	11/15/2018	3,500	$20.1900	$70,665.00
Sale	11/15/2018	126,100	$20.7547	$2,617,166.00
Sale	11/15/2018	32,500	$20.0621	$652,017.50
Sale	11/15/2018	87,400	$20.2773	$1,772,240.00

Note: Documentation supporting the transactions listed in this Annex A, Part II is set forth in Schedule 1, which is appended hereto.

Schedule 1

Documentation for Purchase and Sale Transactions Set Forth in Annex A Part II

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
115487	Buy Long	2/9/2018	2/13/2018	PCG	11,100.00	37.8919	590280782
115486	Buy Long	2/9/2018	2/13/2018	PCG	16,977.00	37.8424	465415954
115479	Buy Long	2/9/2018	2/13/2018	PCG	17,500.00	37.9117	490256234
115484	Buy Long	2/9/2018	2/13/2018	PCG	38,101.00	37.917	564959296
115481	Buy Long	2/9/2018	2/13/2018	PCG	101,700.00	37.805	395696557
115483	Buy Long	2/9/2018	2/13/2018	PCG	35,300.00	37.8471	809062837
115485	Buy Long	2/9/2018	2/13/2018	PCG	207,921.00	37.9011	395637938
115480	Buy Long	2/9/2018	2/13/2018	PCG	17,000.00	37.8865	564981470
115482	Buy Long	2/9/2018	2/13/2018	PCG	26,800.00	37.918	490267648
115528	Buy Long	2/12/2018	2/14/2018	PCG	1,100.00	38.4682	324009766
115530	Buy Long	2/12/2018	2/14/2018	PCG	100,000.00	38.485	439709577
115529	Buy Long	2/12/2018	2/14/2018	PCG	24,900.00	38.50	515934384
115527	Buy Long	2/12/2018	2/14/2018	PCG	1,800.00	38.4619	439703635
115525	Buy Long	2/12/2018	2/14/2018	PCG	5,984.00	38.4764	515920260
115524	Buy Long	2/12/2018	2/14/2018	PCG	1,000.00	38.434	90249914
115526	Buy Long	2/12/2018	2/14/2018	PCG	4,800.00	38.4322	395760469
115523	Buy Long	2/12/2018	2/14/2018	PCG	10,416.00	38.4291	540725436
115739	Buy Long	2/20/2018	2/22/2018	PCG	6,000.00	39.8659	541353312
115736	Buy Long	2/20/2018	2/22/2018	PCG	366,700.00	40.0812	324646278
115740	Buy Long	2/20/2018	2/22/2018	PCG	14,600.00	39.9055	516539237
115741	Buy Long	2/20/2018	2/22/2018	PCG	50,051.00	39.9346	516536196
115735	Buy Long	2/20/2018	2/22/2018	PCG	122,464.00	39.981	090675989
115742	Buy Long	2/20/2018	2/22/2018	PCG	2,500.00	39.9234	090675989
115738	Buy Long	2/20/2018	2/22/2018	PCG	25,300.00	40.0318	491074973

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
115737	Buy Long	2/20/2018	2/22/2018	PCG	78,650.00	39.8352	565733984
115782	Buy Long	2/21/2018	2/23/2018	PCG	268,500.00	40.3538	516626726
115785	Buy Long	2/21/2018	2/23/2018	PCG	5,600.00	40.0591	541414511
115786	Buy Long	2/21/2018	2/23/2018	PCG	5,500.00	40.3777	541409181
115781	Buy Long	2/21/2018	2/23/2018	PCG	41,100.00	40.38	466262891
115784	Buy Long	2/21/2018	2/23/2018	PCG	32,700.00	40.2296	164656525
115788	Buy Long	2/21/2018	2/23/2018	PCG	600,000.00	40.041	417119475
115783	Buy Long	2/21/2018	2/23/2018	PCG	11,000.00	40.3376	466205351
115787	Buy Long	2/21/2018	2/23/2018	PCG	1,100.00	40.3545	491156152
115828	Buy Long	2/22/2018	2/26/2018	PCG	3,410.00	40.1018	417238645
115829	Buy Long	2/22/2018	2/26/2018	PCG	183,100.00	39.9905	440544474
115827	Buy Long	2/22/2018	2/26/2018	PCG	4,900.00	40.0704	591162352
115825	Buy Long	2/22/2018	2/26/2018	PCG	30,004.00	40.0247	466308019
115823	Buy Long	2/22/2018	2/26/2018	PCG	20,000.00	39.99	440583417
115821	Buy Long	2/22/2018	2/26/2018	PCG	4,300.00	40.1908	090758025
115822	Buy Long	2/22/2018	2/26/2018	PCG	375,000.00	40.0906	516714021, 516714018, 516714006
115824	Buy Long	2/22/2018	2/26/2018	PCG	16,400.00	40.1235	565900222
115826	Buy Long	2/22/2018	2/26/2018	PCG	10,422.00	40.0793	516735767
115858	Buy Long	2/23/2018	2/27/2018	PCG	18,400.00	40.80	417326241
115860	Buy Long	2/23/2018	2/27/2018	PCG	30,371.00	40.6648	440633947
115857	Buy Long	2/23/2018	2/27/2018	PCG	39,229.00	40.8545	164851517
115861	Buy Long	2/23/2018	2/27/2018	PCG	2,800.00	40.9945	164851517
115859	Buy Long	2/23/2018	2/27/2018	PCG	4,900.00	40.5858	591256089
115856	Buy Long	2/23/2018	2/27/2018	PCG	2,600.00	40.9481	491348514
115968	Buy Long	2/28/2018	3/2/2018	PCG	25,000.00	40.22	541916470
115970	Buy Long	2/28/2018	3/2/2018	PCG	400.00	40.4925	325249822

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
115969	Buy Long	2/28/2018	3/2/2018	PCG	340.00	40.375	491617919
115971	Buy Long	2/28/2018	3/2/2018	PCG	300.00	40.4933	792497123
115972	Buy Long	2/28/2018	3/2/2018	PCG	100.00	40.465	517150066
115967	Buy Long	2/28/2018	3/2/2018	PCG	1,242.00	40.3275	491643756
116072	Buy Long	3/5/2018	3/7/2018	PCG	119,300.00	40.3696	352172287
116074	Buy Long	3/5/2018	3/7/2018	PCG	100.00	40.48	566584118
116073	Buy Long	3/5/2018	3/7/2018	PCG	3,090.00	40.4612	397207331
116075	Buy Long	3/5/2018	3/7/2018	PCG	100.00	40.48	810063231
118349	Buy Long	5/8/2018	5/10/2018	PCG	300.00	42.495	495932611
118352	Buy Long	5/8/2018	5/10/2018	PCG	1,000.00	42.50	813030543
118348	Buy Long	5/8/2018	5/10/2018	PCG	100.00	42.495	356110818
118424	Buy Long	5/9/2018	5/11/2018	PCG	285,000.00	42.4596	570654106
118423	Buy Long	5/9/2018	5/11/2018	PCG	4,200.00	42.4746	329620045
118422	Buy Long	5/9/2018	5/11/2018	PCG	10,000.00	42.495	329613434
118673	Buy Long	5/16/2018	5/18/2018	PCG	104,300.00	42.4737	445618624
118668	Buy Long	5/16/2018	5/18/2018	PCG	397,016.00	42.50	521898532
118670	Buy Long	5/16/2018	5/18/2018	PCG	4,755.00	42.4911	496449286
118669	Buy Long	5/16/2018	5/18/2018	PCG	23,957.00	42.4747	813438822
118671	Buy Long	5/16/2018	5/18/2018	PCG	300.00	42.495	813438822
118672	Buy Long	5/16/2018	5/18/2018	PCG	19,100.00	42.50	422487565
118726	Buy Long	5/17/2018	5/21/2018	PCG	194,300.00	42.27	496558035
118724	Buy Long	5/17/2018	5/21/2018	PCG	266,000.00	42.45	596375486
118727	Buy Long	5/17/2018	5/21/2018	PCG	1,016.00	42.2151	522071923
118728	Buy Long	5/17/2018	5/21/2018	PCG	38,684.00	42.3662	996739601
120620	Sell Long	7/3/2018	7/6/2018	PCG	(142,200.00)	44.075	499533675
120622	Sell Long	7/3/2018	7/6/2018	PCG	(84,426.00)	44.2049	474608571
120619	Sell Long	7/3/2018	7/6/2018	PCG	(7,700.00)	44.248	574244581
120623	Sell Long	7/3/2018	7/6/2018	PCG	(7,800.00)	44.009	574274058

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
120669	Sell Long	7/5/2018	7/9/2018	PCG	(153,900.00)	43.7847	549834815
120673	Sell Long	7/5/2018	7/9/2018	PCG	(4,600.00)	44.0576	574327101
120668	Sell Long	7/5/2018	7/9/2018	PCG	(201,820.00)	43.996	549809722
120671	Sell Long	7/5/2018	7/9/2018	PCG	(2,500.00)	43.8976	998925016
120672	Sell Long	7/5/2018	7/9/2018	PCG	(50,000.00)	44.18	998925016
120667	Sell Long	7/5/2018	7/9/2018	PCG	(169,000.00)	43.98	400804994
120670	Sell Long	7/5/2018	7/9/2018	PCG	(14,754.00)	43.909	599662630
120952	Buy Long	7/17/2018	7/19/2018	PCG	838,700.00	42.6709	575418920
121623	Buy Long	7/25/2018	7/27/2018	PCG	6,900.00	42.70	449990426
121617	Buy Long	7/25/2018	7/27/2018	PCG	300,000.00	42.8524	550540641
121624	Buy Long	7/25/2018	7/27/2018	PCG	12,700.00	42.9698	450952121
121619	Buy Long	7/25/2018	7/27/2018	PCG	27,650.00	42.6298	550536299
121618	Buy Long	7/25/2018	7/27/2018	PCG	13,056.00	42.8078	97541713
121620	Buy Long	7/25/2018	7/27/2018	PCG	2,600.00	42.7412	97541713
121621	Buy Long	7/25/2018	7/27/2018	PCG	21,700.00	42.6829	360991829
121622	Buy Long	7/25/2018	7/27/2018	PCG	60,981.00	42.6064	450965567
121701	Buy Long	7/26/2018	7/30/2018	PCG	8,962.00	42.8866	334624337
121698	Buy Long	7/26/2018	7/30/2018	PCG	900.00	42.8939	334616509
121702	Buy Long	7/26/2018	7/30/2018	PCG	100.00	42.95	386179172
121697	Buy Long	7/26/2018	7/30/2018	PCG	12,100.00	42.9609	386191839
121700	Buy Long	7/26/2018	7/30/2018	PCG	100.00	42.855	501410929
121807	Buy Long	7/30/2018	8/1/2018	PCG	15,000.00	42.97	451238098
121811	Buy Long	7/30/2018	8/1/2018	PCG	121,560.00	42.93	476021480, 476021476, 476021475
121810	Buy Long	7/30/2018	8/1/2018	PCG	6,000.00	42.926	526282972
121809	Buy Long	7/30/2018	8/1/2018	PCG	49,373.00	42.9232	501586731
121806	Buy Long	7/30/2018	8/1/2018	PCG	32,600.00	42.8776	451239562

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
121808	Buy Long	7/30/2018	8/1/2018	PCG	23,808.00	42.932	576132715
121845	Buy Long	7/31/2018	8/2/2018	PCG	51,000.00	42.995	451345208
121842	Buy Long	7/31/2018	8/2/2018	PCG	300.00	42.95	402399452
121844	Buy Long	7/31/2018	8/2/2018	PCG	83,000.00	42.9535	526379110
121841	Buy Long	7/31/2018	8/2/2018	PCG	200.00	42.96	798859091
121843	Buy Long	7/31/2018	8/2/2018	PCG	2,600.00	42.9838	361353695
121840	Buy Long	7/31/2018	8/2/2018	PCG	1,000.00	43.00	402427486
121880	Buy Long	8/1/2018	8/3/2018	PCG	634,700.00	42.3762	451441452
121884	Buy Long	8/1/2018	8/3/2018	PCG	407,879.00	42.2706	402494271
121878	Buy Long	8/1/2018	8/3/2018	PCG	4,600.00	42.46	386540935
121879	Buy Long	8/1/2018	8/3/2018	PCG	39,115.00	42.4115	402492119
121881	Buy Long	8/1/2018	8/3/2018	PCG	1,000.00	41.73	476173855, 476173842
121877	Buy Long	8/1/2018	8/3/2018	PCG	32,100.00	42.8381	900155441
121882	Buy Long	8/1/2018	8/3/2018	PCG	9,600.00	42.369	425503541
121883	Buy Long	8/1/2018	8/3/2018	PCG	16,816.00	42.4446	526503881
122110	Buy Long	8/9/2018	8/13/2018	PCG	2,800.00	43.9264	426040513
122109	Buy Long	8/9/2018	8/13/2018	PCG	238,778.00	43.9137	387102657
122107	Buy Long	8/9/2018	8/13/2018	PCG	2,700.00	43.9037	502314674, 426030201, 426019163, 387097740, 335451981
122108	Buy Long	8/9/2018	8/13/2018	PCG	2,600.00	43.7115	900549049
122111	Buy Long	8/9/2018	8/13/2018	PCG	180,000.00	43.8409	576853599
122106	Buy Long	8/9/2018	8/13/2018	PCG	44,700.00	43.7766	426058991
122105	Buy Long	8/9/2018	8/13/2018	PCG	37,565.00	43.7422	551522436
122162	Buy Long	8/10/2018	8/14/2018	PCG	1,445,000.00	42.8881	527144314

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
122164	Buy Long	8/10/2018	8/14/2018	PCG	19,600.00	42.865	527144578
122168	Buy Long	8/10/2018	8/14/2018	PCG	7,700.00	42.8551	335536401
122161	Buy Long	8/10/2018	8/14/2018	PCG	198,982.00	42.9086	403116776
122167	Buy Long	8/10/2018	8/14/2018	PCG	5,900.00	42.9137	476780393, 476780387, 476774009, 362013433, 362007084, 362006847, 362006840, 362006790, 335527060, 335526083
122163	Buy Long	8/10/2018	8/14/2018	PCG	708,857.00	42.7635	502405024
122166	Buy Long	8/10/2018	8/14/2018	PCG	63,100.00	42.9899	476801879
122165	Buy Long	8/10/2018	8/14/2018	PCG	41,718.00	42.8689	403138546
122203	Buy Long	8/13/2018	8/15/2018	PCG	839,700.00	42.7466	362127869
122199	Buy Long	8/13/2018	8/15/2018	PCG	662,369.00	42.7431	362127242
122201	Buy Long	8/13/2018	8/15/2018	PCG	8,900.00	42.7566	387247012
122202	Buy Long	8/13/2018	8/15/2018	PCG	27,400.00	42.745	426205858
122200	Buy Long	8/13/2018	8/15/2018	PCG	1,100.00	42.705	476872173
122198	Buy Long	8/13/2018	8/15/2018	PCG	34,700.00	42.7658	362137029
122239	Buy Long	8/14/2018	8/16/2018	PCG	118,300.00	42.8474	362241668
122240	Buy Long	8/14/2018	8/16/2018	PCG	162,543.00	42.9671	502614468
122245	Buy Long	8/14/2018	8/16/2018	PCG	500.00	43.00	577105648
122241	Buy Long	8/14/2018	8/16/2018	PCG	76,382.00	43.0154	426315480
122246	Buy Long	8/14/2018	8/16/2018	PCG	1,000.00	43.01	452241205, 452241152
122242	Buy Long	8/14/2018	8/16/2018	PCG	100,000.00	42.84	799431154
122247	Buy Long	8/14/2018	8/16/2018	PCG	300.00	42.79	799431154

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
122238	Buy Long	8/14/2018	8/16/2018	PCG	600,000.00	42.9897	476937673
122244	Buy Long	8/14/2018	8/16/2018	PCG	3,500.00	42.9481	452262013
122243	Buy Long	8/14/2018	8/16/2018	PCG	46,175.00	42.7826	502618177
122278	Buy Long	8/15/2018	8/17/2018	PCG	45,500.00	43.4415	362360744
122279	Buy Long	8/15/2018	8/17/2018	PCG	25,000.00	43.32	335790504
122275	Buy Long	8/15/2018	8/17/2018	PCG	1,100.00	43.4123	527393203
122281	Buy Long	8/15/2018	8/17/2018	PCG	57,900.00	43.3986	335777993
122276	Buy Long	8/15/2018	8/17/2018	PCG	33,000.00	43.4517	551840210, 551840181, 527388532
122277	Buy Long	8/15/2018	8/17/2018	PCG	200.00	43.40	98411954
122280	Buy Long	8/15/2018	8/17/2018	PCG	26,600.00	43.2966	502694520
122283	Buy Long	8/15/2018	8/17/2018	PCG	49,087.00	43.2102	502698587
122357	Buy Long	8/20/2018	8/22/2018	PCG	1,201,300.00	43.9795	403785919
122411	Buy Long	8/22/2018	8/24/2018	PCG	34,500.00	44.4085	527928162
122414	Buy Long	8/22/2018	8/24/2018	PCG	4,200.00	44.4702	577731531, 577731525, 577731524, 426957014, 387954273, 387954271
122413	Buy Long	8/22/2018	8/24/2018	PCG	15,100.00	44.4313	799845660
122412	Buy Long	8/22/2018	8/24/2018	PCG	14,600.00	44.4357	552499118
122415	Buy Long	8/22/2018	8/24/2018	PCG	4,100.00	44.4213	403934549
122454	Buy Long	8/23/2018	8/27/2018	PCG	51,500.00	44.0297	528029356
122458	Buy Long	8/23/2018	8/27/2018	PCG	17,500.00	44.495	528030238
122456	Buy Long	8/23/2018	8/27/2018	PCG	5,300.00	43.9696	362999334
122451	Buy Long	8/23/2018	8/27/2018	PCG	489,424.00	44.1819	452970684
122455	Buy Long	8/23/2018	8/27/2018	PCG	100,000.00	43.95	427038426

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
122457	Buy Long	8/23/2018	8/27/2018	PCG	400.00	43.96	98755670
122453	Buy Long	8/23/2018	8/27/2018	PCG	39,500.00	44.0576	452981106
122450	Buy Long	8/23/2018	8/27/2018	PCG	232,357.00	44.1269	388064354
122484	Buy Long	8/24/2018	8/28/2018	PCG	22,800.00	42.805	528093080
122491	Buy Long	8/24/2018	8/28/2018	PCG	83,400.00	43.601	528093080
122485	Buy Long	8/24/2018	8/28/2018	PCG	650,000.00	42.8489	336476541, 336476537, 336476505
122488	Buy Long	8/24/2018	8/28/2018	PCG	400.00	42.76	528082455
122486	Buy Long	8/24/2018	8/28/2018	PCG	56,700.00	42.795	363075567
122492	Buy Long	8/24/2018	8/28/2018	PCG	5,563.00	43.177	363075567
122487	Buy Long	8/24/2018	8/28/2018	PCG	1,000.00	42.76	388114862
122490	Buy Long	8/24/2018	8/28/2018	PCG	280,000.00	43.3035	477788567
122489	Buy Long	8/24/2018	8/28/2018	PCG	13,300.00	42.7914	528097508
122539	Buy Long	8/27/2018	8/29/2018	PCG	192,500.00	43.6442	453148035
122535	Buy Long	8/27/2018	8/29/2018	PCG	36,500.00	43.6182	453147389
122538	Buy Long	8/27/2018	8/29/2018	PCG	21,988.00	43.2497	336533942
122531	Buy Long	8/27/2018	8/29/2018	PCG	2,700.00	43.6967	336536776
122533	Buy Long	8/27/2018	8/29/2018	PCG	95,172.00	43.6912	453123758
122534	Buy Long	8/27/2018	8/29/2018	PCG	22,400.00	43.2526	427180887, 388192313, 388191540, 388191474
122532	Buy Long	8/27/2018	8/29/2018	PCG	32,900.00	43.6478	901397256
122536	Buy Long	8/27/2018	8/29/2018	PCG	44,700.00	43.5435	388225489
122537	Buy Long	8/27/2018	8/29/2018	PCG	54,628.00	43.5968	427216067
122584	Buy Long	8/28/2018	8/30/2018	PCG	19,900.00	44.50	477971224
122582	Buy Long	8/28/2018	8/30/2018	PCG	10,800.00	44.50	477970744
122581	Buy Long	8/28/2018	8/30/2018	PCG	2,400.00	44.495	552805622

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
122583	Buy Long	8/28/2018	8/30/2018	PCG	2,200.00	44.4555	528272504
122580	Buy Long	8/28/2018	8/30/2018	PCG	145.00	44.495	477976666
122869	Buy Long	9/7/2018	9/11/2018	PCG	103,500.00	45.23	700602447
122866	Buy Long	9/7/2018	9/11/2018	PCG	60,100.00	45.6605	553446972
122861	Buy Long	9/7/2018	9/11/2018	PCG	300.00	45.69	388889112
122863	Buy Long	9/7/2018	9/11/2018	PCG	95,571.00	45.6784	553431222
122862	Buy Long	9/7/2018	9/11/2018	PCG	200.00	45.68	99310919
122865	Buy Long	9/7/2018	9/11/2018	PCG	17,800.00	45.6831	404812613
122864	Buy Long	9/7/2018	9/11/2018	PCG	82,693.00	45.5665	553472358
123285	Buy Long	9/18/2018	9/20/2018	PCG	15,131.00	47.1285	479184917
123283	Buy Long	9/18/2018	9/20/2018	PCG	200,000.00	47.187	579264217
123284	Buy Long	9/18/2018	9/20/2018	PCG	400.00	47.1488	389562052
123331	Buy Long	9/19/2018	9/21/2018	PCG	49,700.00	46.6616	902557527
123329	Buy Long	9/19/2018	9/21/2018	PCG	3,400.00	46.7491	554111453
123335	Buy Long	9/19/2018	9/21/2018	PCG	153,294.00	46.6849	529535592
123330	Buy Long	9/19/2018	9/21/2018	PCG	2,400.00	46.7746	529517681, 529517660, 337926435, 337923385
123328	Buy Long	9/19/2018	9/21/2018	PCG	9,400.00	46.7904	819671072
123334	Buy Long	9/19/2018	9/21/2018	PCG	852,105.00	46.8542	504780350, 504780345
123333	Buy Long	9/19/2018	9/21/2018	PCG	120,600.00	46.7784	529548846
123332	Buy Long	9/19/2018	9/21/2018	PCG	47,375.00	46.6608	364596429
123385	Buy Long	9/20/2018	9/24/2018	PCG	200.00	46.815	389719277
123388	Buy Long	9/20/2018	9/24/2018	PCG	1,650.00	46.8592	504866479
123389	Buy Long	9/20/2018	9/24/2018	PCG	543,078.00	46.8308	529617712
123386	Buy Long	9/20/2018	9/24/2018	PCG	400.00	46.7225	529636643
123387	Buy Long	9/20/2018	9/24/2018	PCG	867.00	46.7335	454612568

Trade Id	Trans Type	Trade Date	Settle Date	Investment Symbol	Quantity	Price	DTC Number(s)
123437	Sell Long	9/21/2018	9/25/2018	PCG	(275,334.00)	46.9075	389823472
123790	Buy Long	9/26/2018	9/28/2018	PCG	23,600.00	45.275	820108850
123789	Buy Long	9/26/2018	9/28/2018	PCG	900.00	45.30	365041793
123787	Buy Long	9/26/2018	9/28/2018	PCG	12,800.00	45.2133	455003614
123784	Buy Long	9/26/2018	9/28/2018	PCG	48,800.00	45.3738	902943860
123786	Buy Long	9/26/2018	9/28/2018	PCG	25,000.00	45.16	902943860
123788	Buy Long	9/26/2018	9/28/2018	PCG	5,700.00	45.2094	428993720
123785	Buy Long	9/26/2018	9/28/2018	PCG	15,236.00	45.2951	455028518
123831	Buy Long	9/27/2018	10/1/2018	PCG	453,900.00	45.181	820198075
123888	Buy Long	9/28/2018	10/2/2018	PCG	25,891.00	45.6964	701637490
123952	Buy Long	10/1/2018	10/3/2018	PCG	2,500.00	45.5076	390374187
123954	Buy Long	10/1/2018	10/3/2018	PCG	2,400.00	45.5667	406243114, 338731995
123950	Buy Long	10/1/2018	10/3/2018	PCG	400.00	45.44	820345738
123953	Buy Long	10/1/2018	10/3/2018	PCG	131,404.00	45.5872	820345738
123951	Buy Long	10/1/2018	10/3/2018	PCG	51,100.00	45.4612	505541759
126346	Sell Long	11/15/2018	11/19/2018	PCG	(115,400.00)	20.39346187	341939937
126347	Sell Long	11/15/2018	11/19/2018	PCG	(12,600.00)	20.17976191	409364341
126349	Sell Long	11/15/2018	11/19/2018	PCG	(126,100.00)	20.75468676	823497095
126345	Sell Long	11/15/2018	11/19/2018	PCG	(286,770.00)	20.57969153	583229554
126348	Sell Long	11/15/2018	11/19/2018	PCG	(3,500.00)	20.19	533395729
126350	Sell Long	11/15/2018	11/19/2018	PCG	(32,500.00)	20.06207692	704243436
126343	Sell Long	11/15/2018	11/19/2018	PCG	(426,085.00)	21.42492905	704243436
126344	Sell Long	11/15/2018	11/19/2018	PCG	(71,100.00)	20.55262307	368359054
126351	Sell Long	11/15/2018	11/19/2018	PCG	(87,400.00)	20.27734554	393545693

<u>ADDENDUM TO RESCISSION OR DAMAGE CLAIM PROOF OF CLAIM</u>

1. This proof of claim (the "<u>Proof of Claim</u>") is filed by Baupost Group Securities, L.L.C. ("<u>Claimant</u>"), on behalf of itself and as trading nominee for certain funds managed by The Baupost Group, L.L.C. that are the beneficial owners of the equity securities at issue herein (the "<u>Baupost-Managed Funds</u>"), for obligations owing to Claimant and the Baupost-Managed Funds by PG&E Corporation and Pacific Gas and Electric Company (collectively, the "<u>Debtors</u>") under the Securities Exchange Act of 1934, 15 U.S.C. § 78a *et seq*. Claimant purchased and acquired the equity securities that are the subject of this Proof of Claim as a trading nominee for the Baupost-Managed Funds, which are the beneficial owners of such equity securities. The Court's Order (i) Denying Securities Lead Plaintiff's Motion to Apply Bankruptcy Rule 7023 to Class Proof of Claim and (ii) Extending Bar Date for Certain Holders of Securities Claims for Rescission or Damages, dated February 27, 2020 [Dkt. No. 5943] authorizes "those persons or entities (the 'Securities Claimants') that purchased or acquired the Debtors' publicly traded debt and/or equity securities" to file a Rescission or Damage Claim Proof of Claim Form, either directly or through "an authorized agent or attorney."

2. Upon information and belief, Claimant believes the allegations set forth in the Third Amended Consolidated Class Action Complaint for Violation of the Federal of Securities Law filed in *In re PG&E Corp. Securities Litigation*, Civil Action No. 3:18-cv-03509-EJD (N.D. Cal.) [Dkt. No. 121] (the "<u>TAC</u>") are valid and hereby incorporates such allegations herein. Attached hereto as **<u>Exhibit A</u>** is a copy of the TAC cover page and table of contents.

3. Claimant reserves the right to amend, modify, and/or supplement this Proof of Claim at any time, including after any bar date, in any manner, and/or to file additional proofs of claim for any additional claims that may be based on the same or additional documents or grounds of liability, or based on additional facts learned following further investigation.

4. The filing of this Proof of Claim shall be without prejudice to any previous, contemporaneous, or future claims made by or on behalf of the Claimant or any of its affiliates against the Debtors or any of their affiliates in this or any other proceeding. Claimant reserves all rights as against persons and entities other than Debtors that have participated in or benefited from the conduct alleged in the TAC.

5. In executing and filing this Proof of Claim, Claimant does not waive (and this Proof of Claim shall not be deemed or construed to waive) any claims or right to assert any claims, or preserve any remedies, including setoff and recoupment, that Claimant has against Debtors or any of their affiliates, whether arising from or related to the matters described herein or otherwise.

6. The filing of this Proof of Claim is not and shall not be deemed or construed as: (a) a waiver or release of Claimant's rights against any person, entity, or property; (b) a consent by Claimant to the jurisdiction of this Court or any other court with respect to proceedings, if any, commenced in any case against or otherwise involving Claimant; (c) a waiver or release of Claimant's right to trial by jury in this Court or any other court in any proceeding as to any and all matters so triable herein, whether or not the same be designated legal or private rights or in any case, controversy, or proceeding related hereto, notwithstanding the designation or not of such matters as "core proceedings" pursuant to 28 U.S.C. § 157(b)(2), and whether such jury trial right is pursuant to statute or the U.S. Constitution; (d) a consent by Claimant to a jury trial in this Court or any other court in any proceeding as to any and all matters so triable herein or in any case, controversy, or proceeding related hereto, pursuant to 28 U.S.C. § 157(e) or otherwise; (e) a waiver or release of Claimant's right to have any and all final orders in any and all non-core matters or proceedings entered only after *de novo* review by a U.S.

District Court Judge or, if applicable, the Ninth Circuit Court of Appeals; (f) a waiver of the right to move to withdraw the reference with respect to the subject matter of this Proof of Claim, any objection thereto or other proceeding which may be commenced in this case against or otherwise involving Claimant; or (g) an election of remedies.

EXHIBIT A

LABATON SUCHAROW LLP
THOMAS A. DUBBS (*pro hac vice*)
LOUIS GOTTLIEB (*pro hac vice*)
JEFFREY A. DUBBIN (#287199)
ARAM BOGHOSIAN (*pro hac vice*)
140 Broadway
New York, New York 10005
Telephone: (212) 907-0700
Facsimile: (212) 818-0477
Email: tdubbs@labaton.com
lgottlieb@labaton.com
jdubbin@labaton.com
aboghosian@labaton.com

Counsel for Lead Plaintiff the Public Employees Retirement Association of New Mexico and Lead Counsel for the Class

WAGSTAFFE, VON LOEWENFELDT, BUSCH & RADWICK, LLP
JAMES M. WAGSTAFFE (#95535)
FRANK BUSCH (#258288)
100 Pine Street, Suite 725
San Francisco, California 94111
Telephone: (415) 357-8900
Facsimile: (415) 371-0500
Email: wagstaffe@wvbrlaw.com
busch@wvbrlaw.com

Liaison Counsel for the Class

UNITED STATES DISTRICT COURT
NORTHERN DISTRICT OF CALIFORNIA
SAN FRANCISCO DIVISION

IN RE PG&E CORPORATION SECURITIES LITIGATION	Civil Action No. 3:18-cv-03509-EJD THIRD AMENDED CONSOLIDATED CLASS ACTION COMPLAINT FOR VIOLATION OF THE FEDERAL SECURITIES LAWS JURY TRIAL DEMANDED

TABLE OF CONTENTS

Electronic Proof of Claim_PMU*B27423

Final Audit Report 2020-04-15

Created:	2020-04-15
By:	Prime Clerk E-Filing (efiling@primeclerk.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAAQede0QqiuP7-fjcgPPVlwosscC3zcjqr

"Electronic Proof of Claim_PMU*B27423" History

Web Form created by Prime Clerk E-Filing (efiling@primeclerk.com)

2020-04-15 - 10:44:35 PM GMT

Joshua A.S. Greenhill (nova.alindogan@ropesgray.com) uploaded the following supporting documents:

Attachment

2020-04-15 - 10:49:35 PM GMT

Web Form filled in by Joshua A.S. Greenhill (nova.alindogan@ropesgray.com)

2020-04-15 - 10:49:35 PM GMT- IP address: 64.124.52.130

(User email address provided through API User-Agent: Mozilla/5.0 (Windows NT 10.0; Win64; x64) AppleWebKit/537.36 (KHTML, like Gecko) Chrome/80.0.3987.163 Safari/537.36)

2020-04-15 - 10:49:37 PM GMT- IP address: 64.124.52.130

Signed document emailed to Prime Clerk E-Filing (efiling@primeclerk.com) and Joshua A.S. Greenhill (nova.alindogan@ropesgray.com)

2020-04-15 - 10:49:37 PM GMT

EXHIBIT B

Manage trees and plants near power lines

Transmission vs. distribution power lines

Transmission lines

- Carry electricity across the state

- Transport bulk electricity at high voltages ranging from 60 kV-500 kV
- Are usually supported on tall metal towers, but sometimes on wooden poles
- Have different vegetation standards than distribution lines due to the high voltages they carry
- Are managed using the utility industry’s best-management practice of Wire Zone Border Zone
- Require only low-growing vegetation underneath—typically nothing taller than 10 feet at maturity

Our goal is to achieve a sustainable landscape that supports native plants and natural habitats. Trees near these lines can't be managed by pruning and often must be removed.

Distribution lines

- Deliver electricity to neighborhoods and communities over a shorter distance than transmission lines
- Are generally supported by wooden poles and not as high as transmission lines
- Are the final stage of electricity delivery to homes and businesses
- Carry lower voltage electricity that is still powerful enough to cause injury or death

Trees growing near these lines may be managed with directional pruning, but removal is often best.

Get more information

To view guidelines about landscaping and planting near distribution and transmission lines, **visit Right tree, right place**.

Why Does PG&E Care about Keeping Trees Away from Transmission and Distribution Power Lines?

Audio description and transcript also available for this video.

Access an audio descriptive version
Download a transcript (PDF, 19 KB)

PLAY VIDEO

HELP CENTER

CONTACT PG&E

DO NOT SELL MY PERSONAL INFORMATION

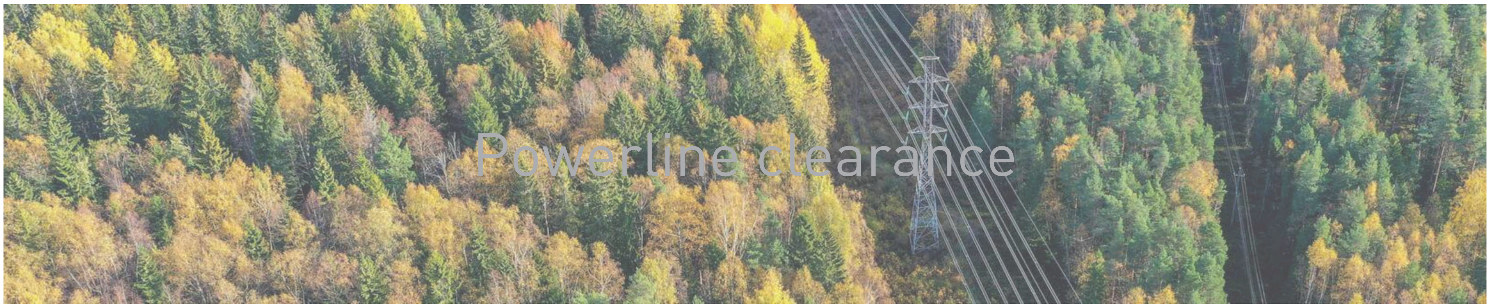
CONNECT WITH PG&E

Menu
MENU

PGE LOGO

EMERGENCIES

POWER LINES & TREES   POWER LINE CLEARANCE



Programs and resources

SELECT ONE

We carefully and frequently review all trees and shrubs located near electric equipment to ensure we are addressing those that pose a safety concern. This annual work takes place across approximately 100,000 miles of overhead powerlines every year, with some locations inspected multiple times a year. As part of this safety work, we:

- Help maintain required safety clearances for each type of powerline
- Maintain clearances surrounding certain types of power poles or towers
- Increase wildfire safety through enhanced vegetation management
- Remove hazardous vegetation, such as dead, diseased, dying or defective trees that pose a potential risk to the lines or equipment

Enhanced Vegetation Management

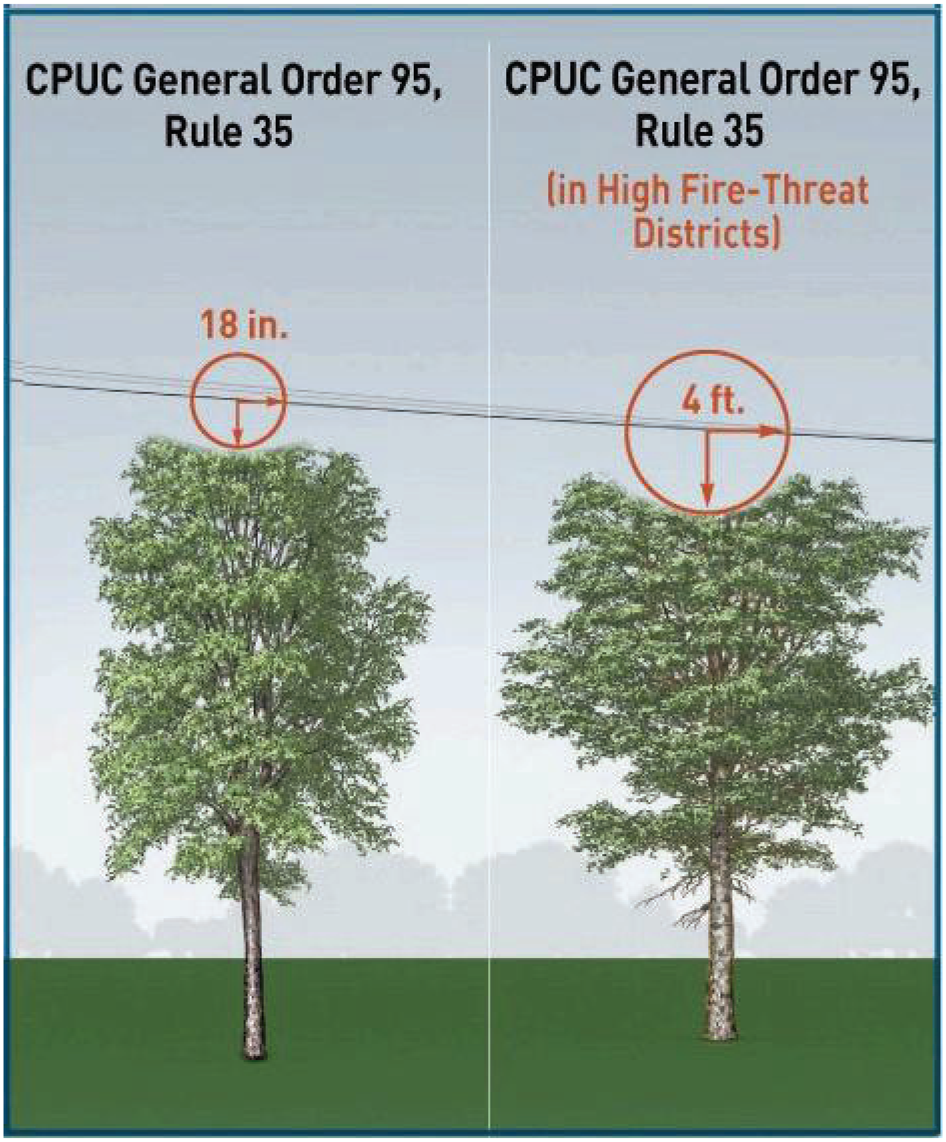
Learn about our enhanced vegetation management work in high fire-threat districts on our **Wildfire Safety Measures page**.

Addressing drought and tree mortality

To help ensure public safety and address the ongoing effects of the bark beetle infestation and drought, we continue to inspect and remove dead and dying trees to prevent them from falling into powerlines and potentially causing wildfires and power outages. Our drought and tree mortality response includes increased vegetation inspections, removal of dead and dying trees and wood management to qualifying properties.

CHOOSE VIEW

Usually located at the top of wood poles above the pole-mounted transformer, distribution lines deliver power into local neighborhoods. PG&E maintains a minimum clearance of 18 inches around these powerlines in non-high fire-threat areas. In High Fire-Threat Districts (HFTD), as designated by the California Public Utilities Commission (CPUC), a minimum 4-foot clearance is required with recommended minimum clearances of 12 feet at the time of pruning to maintain clearance year-round.



Our work near distribution lines includes:

- **Notifications:** As a first step, we leave a door hanger to notify you of upcoming safety inspections to identify trees that require pruning or removal to maintain required safety clearances over the next year.

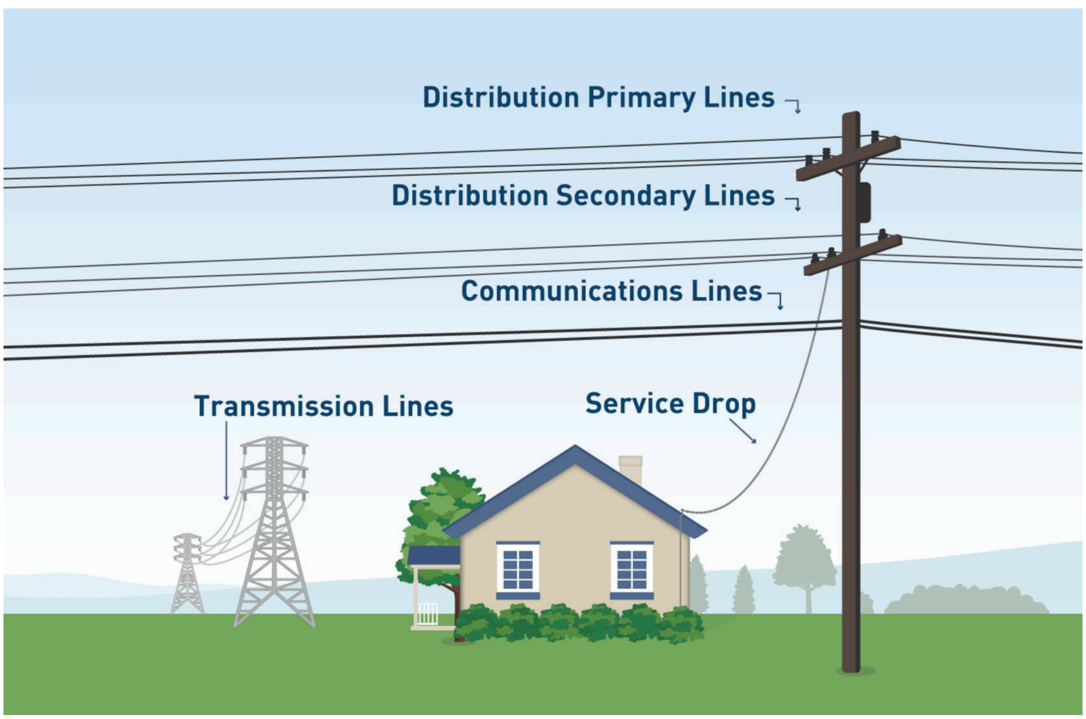
- **Inspections:** Our tree safety inspectors mark trees that require pruning with paint using a dot at the base of the tree. They also look for trees that present a safety hazard and must be removed. These trees are typically marked with an "X."

- **Tree work:** Our certified tree contractors typically return within 4 to 6 weeks of the inspections to prune and remove marked trees.

- **Wood debris:** When work is complete, we chip any wood that is less than 4 inches in diameter and leave the chips on-site. Larger wood debris is cut to a manageable size and is left for the customer to use for firewood or to dispose of as they wish. Wood or wood debris generated from vegetation management work legally belongs to the property owner.

Pruning trees near service wires

Customers are responsible for maintaining the service wire that runs from PG&E's electric pole to your home, and PG&E will not prune trees or vegetation along that line. You can request a free temporary service disconnect so you or a contractor can safely work around the service wire.



About PG&E

Company Information

Workshops & Events

Sitemap

PG&E Newsroom

For Our Business Partners

Environment

Careers

First Responder Resources

Accessibility

Regulation

Privacy

Security

Terms & Conditions

Site Feedback

HELP CENTER

CONTACT PG&E

DO NOT SELL MY PERSONAL INFORMATION

CONNECT WITH PG&E

EXHIBIT C

Study of
Risk Assessment and
PG&E's GRC

Presented to:

The Safety and Enforcement Division
The California
Public Utilities Commission

Presented by:

The Liberty Consulting Group

May 6, 2013

65 Main Street, P.O. Box 1237
Quentin, Pennsylvania 17083
(717) 270-4500 (voice)
(717) 270-0555 (facsimile)

admin@libertyconsultinggroup.com

Overall Summary of Conclusions and Recommendations

Liberty conducted an independent review of capital and operations and maintenance expenditures proposed by Pacific Gas & Electric Company (PG&E) in its General Rate Case (GRC) filing, insofar as they address safety and security initiatives by its Power Generation and Electric Operations lines of business. We focused on PG&E's current and intended use of risk assessment to support such initiatives. Our scope excluded cyber security. Our review of Power Generation excluded nuclear operations, which meant that hydro operations comprised the primary focus of our work there. Our scope included the distribution portion of the work performed by PG&E's Electric Operations line of business.

Two principal documents formed the basis for our scope: (a) the March 5, 2012 letter to PG&E from the Commission's Executive Director, and (b) the contract under which we performed this review. We did not undertake a review intended to propose adjustments to or disallowances of PG&E's proposed safety and security initiatives. The principal areas we addressed were:

- The framework, methods, practices, and activities PG&E has used in assessing risk and relating it to proposed capital and operations and maintenance expenditures
- Whether PG&E has adequately assessed the physical condition of its power generation and electricity distribution systems
- Whether PG&E has explicitly founded proposed safety and security expenditures on explicit risk assessment processes
- Whether those processes demonstrate the appropriateness of proposed expenditures
- Whether and to what extent PG&E's proposals will reduce public and employee risks
- Whether the GRC filing supports safety initiatives with credible cost/benefit analyses
- Whether PG&E's proposed safety initiatives will reduce safety risks and whether one can determine the degree of such reduction
- Whether one can determine if additional expenditures would produce corresponding safety improvements.

The next sections of this chapter summarize the conclusions resulting from our study.

A. PG&E's GRC Filing versus CPUC Expectations

1. Conclusions

1. PG&E's 2014 GRC filing reflects the status of proposed programs and initiatives as of the first quarter of 2012. The timing of the March 5, 2012 letter meant that the structure and content of the 2014 GRC filing would not substantially exhibit the expected relationships and linkages between risk and proposed safety and security projects and initiatives.
2. The opportunities created by the March 5 letter can create a new regulatory paradigm. PG&E has not yet seized the opportunity in this new paradigm, but can do so in the future, if it can accelerate the implementation of planned incorporation of structured, robust consideration of risk as a front-end element of its integrated planning and budgeting processes.
3. The expectations created by the March 5 letter anticipate a use of risk assessment that is beyond what one finds currently in the industry. The expectations are appropriate to the circumstances, but should be accompanied by recognition that a development period will be necessary and that one can expect any "steady state" eventually achieved to fall short of producing a fully objective and completely quantified linkage between risk assessment and expenditure levels.
4. A strengthened and accelerated risk management implementation program by PG&E can bring it to a leading-edge position in the industry in terms of the comprehensiveness and use of risk analysis in driving plans, budgets, and, in turn, rate filings.
5. Risk assessments employing robust quantification of probabilities, consequences, and mitigation opportunities cannot happen at PG&E until 2014 at the earliest. Using such assessments to drive capital and O&M planning and budgeting will therefore not occur before that time.
6. It will require strong executive level structure and support, continued efforts at culture change, and an acceleration of the current rate of progress to achieve reasonably full implementation in time for the next anticipated GRC cycle.
7. Key senior leadership believes correctly that it will be several years and perhaps past the next GRC filing before the process reaches maturity. The opinions of less senior leadership are generally more optimistic.

8. The general nature of rate proceedings involving an individual company does not create an optimum environment for promoting and testing the effectiveness of the changes it will take to move PG&E toward the state anticipated by the March 5 letter. Consideration of a different context and of an approach allowing for thought of statewide consistency where appropriate will help reinforce to the state's utilities the Commission's continuing emphasis on enhanced consideration of risk assessment in connection with safety spending, promote the development of best practices, and establish useful levels of consistency.

2. Recommendations

1. PG&E should respond promptly to the March 5, 2012 letter with a proactive and specific plan and schedule for compliance with the expectations articulated in the letter.
2. PG&E should increase the organizational emphasis on risk management, recognizing and responding to the need for enhancing the pace and the "buy-in" of the business units to the new risk management program.
3. The stakeholders should consider the optimum means outside the GRC context for underscoring the long-term nature of the interest in enhanced use of risk assessment in considering safety matters and for addressing the merits of a comprehensive approach by the state's energy utilities.
4. There should be a structured, comprehensive process for providing to the Commission, regular reports of amounts actually spent versus GRC forecasts, supported by analysis and explanation of variances.

B. Proposed GRC Funding and Projects

1. General Conclusions

1. PG&E did not apply top-down spending limits that would serve to constrain development of the 2014 GRC capital and expense forecasts in the areas we examined.
2. PG&E planned for and spent well above its GRC- authorized capital and expenditure levels in 2011 and 2012, and planned to do so again in 2013, in significant part to improve safety.

3. The 2011 Electric Operations "Improvement Plan" and the "Asset Management Public Safety Acceleration Plan" applicable to Power Generation focused on safety, and drove incremental GRC electric capital expenditures and expenses for 2014-2016.
4. Narrative explanations and engineering judgment, rather than structured risk assessment processes or cost/benefit analyses generally drove GRC-proposed safety and security spending in the areas we examined. The filing generally did not provide rationales for why the chosen spending levels are appropriate and how they were determined.
5. The GRC has generally not documented how expenditures to address safety and security are in proportion to or otherwise aligned with identified risks identified. PG&E has generally not demonstrated analytically that the benefits of proposed safety and security risk mitigation measures justify their costs.

2. General Recommendations

1. PG&E should provide an improved justification and rationale for proposed GRC safety spending levels. Additional information that should be provided includes:
    - Compelling safety objectives and benchmarks that drive spending levels
    - A long term vision of what the future infrastructure looks like
    - A long term plan to achieve that vision
    - An analysis of associated rates to assure sustainability
    - Linkage of safety projects and initiatives to the achievement of long term objectives
    - Analysis / justification of the safety spending levels
        - The safety metrics that will be achieved due to the expenditures
        - Why that optimizes achieving objectives in an appropriate time frame
        - The benefits that will result
        - The benefits or consequences of more or less spending.

3. Generation Conclusions

1. The GRC projects and programs proposed do address important safety risks. Specifically, we determined that: (a) the elevation of priorities in Power Generation has been appropriate and successful, (b) the nature of the projects is consistent with the needs of the system and the new priorities, (c) the technical development of projects is strong and they are suitably

justified and of adequate quality, and (d) while linkage to risk assessments remains limited, a picture of how this can and should work in the future has emerged and the vision seems to be absolutely attainable.

2. The combination of GRC implementation (the GRC ultimately authorizes total spending, rather than spending at the project, program, or initiative level) and Power Generation's internal workings make it very unlikely that the unit's projects that actually get done in 2014 will match the GRC list very closely. Given the expectation that safety projects, programs, and initiatives will result from structured and focused risk analysis, a logical next question to examine is the degree to which it becomes appropriate to provide for some level of monitoring and accountability for expenditures and accompanying results at the same levels.

4. Generation Recommendations

1. Power Generation should modify the planning process in the future to: (a) provide allowances for new and carryover work and (b) provide the list of projects that are proposed to be deferred if less than requested funding is granted by the Commission.

5. Distribution Conclusions

1. The Electric Operations Improvement Plan, which is not founded on structured risk assessments, has nevertheless served as a driver of GRC initiatives to mitigate safety risks.
2. PG&E has undertaken strong and appropriate action to address wildfire and seismic risks for some time.
3. Addressing risks associated with electrical distribution components has been overshadowed by electric transmission and gas facilities.
4. Addressing aging infrastructure and adding SCADA to the system comprise the major focuses of safety initiatives for the distribution system.
5. Current employee/contractor serious injury and fatality levels require significantly greater mitigation. The addition of safety personnel is in line with other electric utilities and should contribute to improving field safety.

6. Distribution Recommendations

1. The two conductor replacement projects should be restructured to: (a) Complement rather than compete with each other, (b) establish program controls to contain and reduce the unit cost, and (c) develop a plan to fully assess the situation.

C. PG&E's Risk Program and Approach

1. Conclusions

1. PG&E's new integrated planning process represents a significant upgrade over its previous processes and would place the Company at the industry's leading edge. PG&E's new planning processes are innovative and well-designed to provide for better linkage of strategy and goals to resource allocation and execution.
2. PG&E lacks a defined and articulated philosophy of risk. This gap creates an impediment to reaching a common understanding between the utility and its stakeholders, particularly the Commission.
3. The lack of a mutually agreeable definition of "safety project" creates another impediment to the fulfillment of the CPUC expectations.
4. PG&E has made substantial progress in developing leading-edge corporate-wide risk assessment processes, but actual follow-through at the lines of business has lagged.
5. The 2014 GRC does not include structured and quantified risk assessments as a basis for developing capital and operating expense requests. Risk assessment processes that drive work plans and safety and security spending were researched in 2011, underwent initial development in 2012, and are just now undergoing testing as part of PG&E's planning cycle.
6. There remain corporate culture barriers that slow the process that the two business units we examined will need to fully embrace to make structured risk management an integrated part of planning and budgeting.
7. The defined governance provisions of the program are strong, but it is not clear that they are working as intended.

2. Recommendations

1. PG&E should define its proposed philosophy of risk and undertake an initiative to reach consensus on that philosophy with the Commission.
2. PG&E should develop a definition of "safety project" with concurrence by the Commission, such that the future of the program has a common basis for reporting.
3. Executive sponsorship of risk management within the responsibility of the current incumbent would be enhanced by changing his reporting from the CFO to the CEO.
4. The corporate risk organization would be significantly enhanced with the addition of a person with long and senior utility operating experience.
5. PG&E needs to recognize that the effective implementation of the program requires an inducement of culture change in how the Company assesses and uses risk considerations and a sense of greater urgency in moving toward its expected steady state.
6. PG&E should consider the addition of an "infrastructure sustainability risk" to its enterprise risks. For example: "The risk that infrastructure deteriorates (due to age and/or other factors) at a pace and to an extent that makes future recovery prohibitively expensive."
7. Corporate risk management should enhance its plans for assuring effective exercise of LOB risk functions, including efforts to ensure that risk considerations are being applied in accordance with program expectations, that appropriate risk scenarios are being examined, that monitoring of preparation and implementation of risk response plans is active, and that analysis and reporting on program status and effectiveness is meaningful and comprehensive.

D. Risk Methods and Techniques

1. General

1. The tools and techniques that PG&E is incorporating into its developing operations risk management program conform to current best practices, including:
    - A structured approach
    - Defined evaluation criteria and mechanics for scoring
    - An assessment tool linked to probability and consequences
    - The concept of inherent and residual risk
    - The conceptual approach to alternatives analysis

- A high level of effort
- A direct tie into the annual integrated planning process
- Resources and funding specifically tailored to mitigate risk gaps.

2. Generation Conclusions

1. Power Generation uses a strong Risk Evaluation Tool (RET), but the resulting risk rankings do not make the contribution one should expect. Expansion of probability and consequences rankings beyond the operation risk level to more detailed tasks would be helpful.
2. Risk scores produced through the use of the RET program lack meaning and limit the effectiveness of the tool as a means of analyzing degrees of risk and mitigation.
3. The alternatives analysis process does not appear to be meeting internal requirements, with the result that alternates do not undergo sufficient ventilation and consideration.
4. The inability to present a coherent story on the scope of the implementation work for the hydro risk, its eventual cost, its schedule, and what the hydro system looks like when it is done (*i.e.*, how the risk profile has changed), is a significant shortcoming.

3. Generation Recommendations

1. Power Generation should develop a consistent approach towards safety project/task prioritization using likelihood and consequences and applying priorities uniformly across all projects and tasks.
2. Power Generation should refine risk score methods to facilitate more effective analysis of risks and degrees of mitigation.
3. Power Generation should align the required approach with alternatives analysis in order to provide management a full range of options and suitable documentation of dismissed options is retained.
4. Power Generation should provide periodic reports that meet the standard of good project management, including credible analysis of cost, schedule, project issues, and other information needed for effective oversight.

4. Distribution Conclusions

1. The Risk and Compliance templates: (a) treat probabilities and consequences in only a partial and preliminary way, (b) base probabilities and consequences on a judgmental process, (c) encompass a small number of operational risks, and (d) include no layered approach that considers a range of potential mitigation measures.
2. The revised Electric Operations organizational structure is better positioned to address aging infrastructure and system safety issues.
3. The vegetation management program, the wood pole program, and the substation asset strategy program comprise base activities that PG&E operates effectively.
4. Since 2010, PG&E has substantially increased public outreach programs to reduce electrical contact incidents.

E. Technical Observations

1. Generation Conclusions

1. We found no concern with the effectiveness of dam safety management. It appears strong and growing stronger.
2. The issue of public safety has an appropriate place in the hierarchy of priorities.
3. Power Generation should place greater weight on age when evaluating risk and replacement decisions such that the system as a whole does not age too quickly.
4. The continued use of contractors as the primary production resources of the Asset Management group limits PG&E's development of internal capabilities and seems inconsistent with PG's technical objectives.

2. Generation Recommendations

1. Power Generation should in the future provide for a direct link between each identified safety project in a GRC and the risk that generated the project.
2. Power Generation should provide in Project Portfolio Management (PPM) for the preservation and use of the Risk Evaluation Tool scores throughout the life of a project. Also, these scores should have some impact, perhaps a dominant one, on the PPM ranking.

3. Power Generation should revise he PPM scoring methodology such that the resulting scores are over a manageable range and the relative values of the scores have some reasonable physical meaning.
4. Power Generation should modify PPM to facilitate the linkage of risks to projects.
5. Power Generation should review the composition of the Asset Management group with the intent of reducing reliance on contractors and strengthening internal technical expertise and capability.
6. Power Generation should adopt a more aggressive schedule for the preparation of risk response plans (RRPs). RRPs should be broken into smaller packages if the size of the package is too big to expeditiously complete.
7. Power Generation should change its approach to defining and structuring projects such that the work can be packaged in a manageable way, so management has a clear picture of the scope, cost, schedule, and intended results, and so project managers have the tools they need to effectively manage the work.

3. Distribution Conclusions

1. Several aspects of the PG&E distribution system present significant safety issues, including especially:
   - The unigrounded 12,470 volt three-wire system that serves as the predominant 12 kV configuration.
   - PG&E employs about 22 thousand miles (approximately 20 percent of primary voltage overhead distribution conductor) of obsolete #6 copper.
   - PG&E also has 47,542 miles of #4 Aluminum Conductor Steel Reinforced (ACSR) conductor on its distribution system. Corrosion issues make this conductor no longer recommended for use in coastal areas.
2. The wood pole and vegetation management initiatives, although not driven by structured risk assessment or cost/benefit analysis, nevertheless generally represent appropriate and effectively managed responses to underlying safety issues.

4. Distribution Recommendations

1. The absence of a formal distribution asset management program is a weakness that should be corrected.
2. The overhead conductor replacement program appears to suffer from higher than expected unit costs; more effective project controls should be implemented.
3. Improve the safety performance metrics by: (a) replacing the Electrical Incidents Resulting from Equipment Failure metric with the Third Party Contacts Incident metric, (b) adding $/ft conductor replacement metric, and (c) raising the bar on the 911 Emergency Response metric.

F. Response to the Commission's Seven Specific Risk Questions

1. *Will the projects reduce risk to ALARP levels?* No. ALARP is not a criterion for PG&E's risk and mitigation program, nor do we necessarily see suitable opportunities for its application. Further study of specific, limited applications would be as far as might be recommended at this time.

2. *Do projects have a credible cost/benefit analysis?* No. Costs and project justifications are included in the work papers, but a credible CBA is not. We emphasize that CBAs are problematic in areas such as safety – they are neither easy to perform, nor are they always fruitful. This does not mean they should not be addressed when practical.

3. *Was the physical condition of the system adequately considered?* It was, and exceptionally so in Power Generation. The asset management work was excellent and what started as a good effort was accelerated further on multiple occasions. The same was not so in electric distribution in the case of deteriorated conductors. PG&E has not yet fully assessed the extent of this condition.

4. *Were projects linked to a risk assessment?* Generally, no. Some projects do flow from the ERM hydro risk, but the path is not a straight line.

5. *Were a prudent set of alternatives considered for each project?* There is generally no record of such consideration.

6. *Will projects reduce risk and enhance safety?* Yes, without question.

7. *Can the degree of enhancement be quantified?* No. As with the cost/benefit issue, this is a difficult question to answer; although there is some potential here for use of the RET for this purpose.

Table of Contents

List of Acronyms

AAAC	Aluminum Alloy Conductors
ACHQ	Alternate Company Headquarters
ACSR	Aluminum Conductor Steel Reinforced (Conductor)
ADA	Americans With Disabilities Act
AEOC	Alternate Emergency Operations Center
ALARA	As Low as Reasonably Achievable
ALARP	As Low as Reasonably Practicable
ANSI	American National Standards Institute
BTL	Below The Line
CBA	Cost Benefit Analysis
CBM	Condition Based Maintenance
CIP	Critical Infrastructure Protection
CPUC	The California Public Utilities Commission
CRE	Corporate Real Estate
CRMC	Compliance and Risk Management Committee
DMS	Distribution Management System
DNV	Det Norske Veritas
DSOD	California Division of Safety of Dams
DTE	Detroit Edison
EAPs	Emergency Action Plans
EDO	Electric Distribution Operations
EMAs	Emergency Management Agencies
EP&PP	Emergency Preparedness & Public Partnership
ERM	Enterprise Risk Management
FRAP	Fire and Resource Assessment Program
FRM	Fire Risk Management
FLISR	Fault Location, Isolation and Service Restoration
GEMS	Gas and Electric Mapping System
GRC	General Rate Case

ICS	Incident Command System
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
Liberty	The Liberty Consulting Group
LOB	Line of Business
LWD	Lost Work Day
MWC	Major Work Category
NIMS	National Incident Management System
NOI	Notice of Intent
OPC	Operating Plan Committee
O&M	Operations and Maintenance
PC	Personal Computer
PG&E	Pacific Gas and Electric Company
PILC	Paper Insulation/Lead Cover
PPM	Project and Portfolio Management
QRB2	Quarterly Business Review #2
QRB3	Quarterly Business Review #3
RAT	Risk Assessment Tool
RIDM	Risk Informed Decision Making
RPC	Risk Policy Committee
RRP	Risk Response Plan
SCADA	Supervisory Control and Data Acquisition
STAR	System Tool for Asset Risk
S&S	Safety and Security
S-1	Operation Planning Session #1
S-2	Operation Planning Session #2
TGRAM	Transfer Ground Rocker Arm Main
TGRAL	Transfer Ground Rocker Arm Line
T&D	Transmission and Distribution
URD	Underground Residential Distribution
USFS	United States Forest Service

UWF	Urban Wildland Fire
VLF	Very Low Frequency
VM	Vegetation Management
#6Cu	Number 6 Copper (conductor)

List of Tables and Figures

I. Introduction

A. Structure of this Report

This report presents the results of a study that The Liberty Consulting Group (Liberty) performed for the Safety and Enforcement Division of the California Public Utilities Commission to address the risk assessment at Pacific Gas & Electric Company (PG&E) generally, and specifically with reference to its use in supporting certain safety and security projects, programs, and initiatives in the current PG&E General Rate Case filing. We prepared a description of the study's major conclusions and recommendations. It precedes this report, and provides an overall summary of study results. This detailed report begins with descriptions of the study's objectives and scope.

We then describe our study standards and criteria focused around the principal questions to which the Safety and Enforcement Division sought answers. The report focuses attention on a March 5, 2012 letter from the Commission's Executive Director to the Company. The report explains our belief that this letter creates certain expectations that, while, as PG&E concedes are appropriate, will nevertheless move not only PG&E forward, but also the U.S. energy utility industry generally. The report also explains how meeting these expectations will create a new regulatory paradigm that can benefit all stakeholders.

The report then explains our views about the connection between risk assessment and safety, the variety of ways that companies can structure consideration and analysis of that connection, how PG&E currently does so, and the direction it seeks for the future. We then summarize our overall conclusions in some detail, again focusing on the principal questions we sought to answer.

The detailed information and findings that support these conclusions lie principally in the next three chapters of this report. The first of these three chapters addresses the corporate approaches, programs, initiatives, and activities: (a) through which PG&E has used risk assessment and linked it to GRC spending requests, and (b) by which it seeks to enhance its use of risk assessment and its linkage to future plans, budgets, and eventually GRC cost forecasts. The second two address the risk assessment status and plans for the two sectors of PG&E that our work scope included: (a) the Power Generation sector of the Energy Supply unit (consisting

predominantly of hydro generation), and (b) the groups responsible for the electricity distribution system, which lie within the Electric Operations unit. A final chapter addresses safety and security initiatives of other units that affect power generation and electricity distribution.

This report owes much to the efforts of PG&E, whose people fully supported our data gathering and interviewing efforts, which were substantial. This report owes equally much to the Safety and Enforcement Division, which was responsible to administer the contract. We emphasize that the opinions, conclusions, and recommendations of the report are solely the product of our team, which conducted a strictly independent study of the matters addressed herein.

B. Study Objectives

The San Bruno incident and the "lessons learned" that emerged have spurred growing support for a more aggressive approach to assuring public safety. We found this change evident at PG&E in corporate-wide programs aimed at better identification and mitigation of business risks, including those having safety implications. The Company's work took on particular momentum in mid-2011 following issuance of the report of the Independent Review Panel (IRP).

The resulting corrective activities underway as PG&E began preparations for its next rate filing made clear that public safety would have a major role in the rate case. Required spending on gas facilities was anticipated to be extremely high, and a growing interest in the public safety elements of the electric business also became apparent.

The California Public Utilities Commission (CPUC) was at the same time seeking to determine how better to fulfill its safety role. A "Straw Proposal" discussed various approaches to improving the ratemaking process to facilitate safety initiatives. This proposal served as a discussion focus for a stakeholders' workshop in January 2012. Then came a March 5, 2012 letter to PG&E from the CPUC's Executive Director (the March 5 letter). It defines a new focus on public safety for the ratemaking process, on defining system risks, and addressing the funding of risk mitigation. The CPUC decided that consultants should be retained to review the aspects of PG&E's coming GRC related to safety and security. Liberty was chosen to examine electric distribution and electric generation.

The major expectations expressed for Liberty's work included evaluating the:

- Quality of the safety and security proposals in the 2014 GRC filing.
- Degree to which safety and security proposals flow from effective risk assessments.
- Effectiveness of PG&E decision-making regarding related spending choices.

C. Study Scope

Liberty's study addressed employee and public safety and security risks that can affect safety. A definition of safety in this context has proven elusive. PG&E considers much of its expenditures related to safety and this is clearly true. The industry generally and PG&E as well tend liberally to designate expenditures as safety related. That tendency is not particularly helpful for this analysis, which seeks to focus on real initiatives directed at real risks to safety and security.

The scope of our examination included safety and security initiatives in non-nuclear (predominantly hydro) power generation and in electricity distribution (*i.e.,* excluding transmission). This scope made the Power Generation unit of PG&E's Energy Supply Line of Business (LOB or business unit) and the Electric Operations LOB the primary focuses of our work. We also looked at the initiatives of other PG&E LOBs to the extent they involved power generation or electricity distribution safety.

D. Standards and Criteria

Liberty undertook this study under the following general standards:

- *Industry best practices and standards*: much of the work associated with this project is breaking new ground; nevertheless, there is a level of existing industry practice and similar utility tasks that? also shed light on how others approach such challenges.
- *The March 5, 2012 letter*, which established a clear set of GRC expectations.
- The CPUC RFP and our resulting contract.

We focused our inquiries on the following questions, considering specific criteria, which Appendix A to this report summarizes.

BASELINE QUESTIONS ABOUT SAFETY AND SECURITY RISK

1. How have Commission expectations changed regarding analysis of safety and security risk?
2. What are the Commission's expectations with respect to connecting risk analysis with proposed revenue requirements in the filing?
3. How do those expectations compare with industry best practice?
4. How has PG&E constructed this filing differently from prior filings with respect to risk?
5. How does the PG&E GRC filing identify and quantify safety and security spending and justify the increased revenue requirements?

CORPORATE SAFEY AND SECURITY RISK MANAGEMENT

6. What changes has PG&E made with respect to risk analysis and its use since the San Bruno incident?
7. What is PG&E's expected end-state with respect to risk analyses and their use?
8. What are PG&E's plan and schedule for reaching that state?
9. What progress can one expect PG&E to have made to date, and how does that compare with what the Company has done so far?
10. Can one use PG&E's assessments to assess in reasonably robust ways the probabilities and consequences of failures associated with safety and security risks?

LOB-LEVEL SAFETY & SECURITY RISK MANAGEMENT

11. Does PG&E use standard and consistent risk assessment processes?
12. Has PG&E adequately assessed the physical condition of its system (both physical assets and supporting systems)?
13. How do the LOBs identify and assess safety and security risks?
14. How have methods used and results obtained changed since San Bruno?
15. How do they compare with industry best practices?
16. How do those assessments affect budgeting for projects and programs?
17. Are changes in project and program emphases apparent?

SAFETY AND RISK IN OPERATIONS PLANNING

18. What is the overall process flow for determining operations plans and spending levels and allocations?

19. How has the operations planning process changed to reflect changes in how risks are identified and managed?
20. In what ways do corporate level activities specifically consider risks?
21. Did the process leading to the current rate filing incorporate material changes with respect to consideration of risk?
22. Are such changes clearly reflected in approved operating plans?
23. Does the planning process allow for robust consideration of risk before spending allocations and limits become resistant to change?

RISK/REVENUE REQUIREMENT NEXUS

24. What capital and O&M projects and programs in the GRC filing did the Company identify by applying safety and security considerations?
25. Are these projects founded on an explicit safety and security risk assessment?
26. Has the Company laid an adequate foundation for concluding that expenditures to address safety and security and security risks are in proportion to risks properly identified?
27. How and to what measurable extent will those projects and programs reduce identified risks?
28. Has the Company sufficiently demonstrated that the benefits of proposed safety and security risk mitigation measures justify their costs?
29. Does the degree of risk reduction reach a level that should be considered satisfactory from customer, public, and employee perspectives?
30. Can one apply PG&E's risk assessments to determine the appropriateness of related projects and programs and of the costs associated with them?

E. A New Regulatory Paradigm?

The March 5 letter creates expectations that would change the ways that we have seen utilities use risk assessment and justify safety spending in rate proceedings. We believe that centering safety and security programs on specific risks, and the degree that such risks can be mitigated, has great potential for benefitting all stakeholders. Meeting the letter's expectations will promote much greater transparency in how safety needs are identified and proposed to be met through specific initiatives. That transparency will allow stakeholders to engage in a much more robust process of valuing the benefits of expenditures, both relative to alternatives for addressing safety risks, and relative to the other risks and opportunities (*e.g.*, reliability, customer satisfaction, and

environmental stewardship) that must be balanced if vital public services are to continue to remain economically sustainable.

In short, we see the March 5 letter as creating an excellent opportunity for the Company and other California utilities. PG&E has taken substantial actions in enhancing its focus on safety, but has not seized this new opportunity in the current GRC. The Company identified the specific responsive actions associated with the GRC:

- Adding risk policy testimony added to Exhibit 1 and elsewhere in the GRC testimony
- Instructing LOBs to review GRC forecasts and testimony to affirm that operating risk management was included and that the forecast closed identified risk gaps.

PG&E did not consider significantly revising the GRC forecast to address specifically the March 5 letter. Revising its GRC forecast was not consistent with meeting July 2012 target for Notice of Intent ("NOI") filing and other Rate Plan scheduling requirements. PG&E has stated that the letter did not come as a surprise; its contents were discussed at the January 2012 CPUC risk workshop. PG&E recognized that a fully mature, structured operating risk management program would only be able to occur well into the future, and only then could drive planning and budgeting of capital and operating expenditures.

The PG&E work related to safety generally exceeds the risk and public safety emphasis of utilities we have observed. It does not, however, yet meet the new regulatory expectations. The letter certainly constrained PG&E's options to respond in the GRC filing itself. Nevertheless, more than a year has passed since then, making what has been done in that period a material indicator of the quality of PG&E's response. Understanding this timing issue, we began our work focusing on measuring the trajectory of its plan for compliance as opposed to the actual level of performance achieved at that time. We became concerned, however, as our study progressed, with the lack of an apparent explanation of what PG&E viewed as that trajectory, in terms of both plans and schedules for supporting it. Moreover, we found that there was not a consensus within the Company on where it stood along that trajectory.

An overriding conclusion of our study is that PG&E needs more fully to seize the opportunities presented in the March 5 letter. The letter proposes a new paradigm – one seeking a shared objective of assuring adequate spending on public safety by advancing new risk-based techniques that will make the value of such investments more apparent to customers and other stakeholders. This approach surely will serve the Company's best interests as well. We therefore consider it of paramount importance that that PG&E respond to the March 5 letter in a structured manner, proposing a robust and energetic plan and schedule for making its future efforts in risk and safety consistent with the ideas it communicates.

F. The Nexus Between Risk and Safety

Our study focused on examining linkages between risk assessment and proposed safety and security projects and programs. We consider the requirement for a linkage to risk to present a new approach that will move not just PG&E, but the entire industry forward. That it is new certainly requires patience in developing it, and temperance in assessing how close to the ideal one can come in light of the novelty and the difficulty that applying that linkage entail. Among the benefits we see are:

- A stronger foundation for proposed work. There is no question as to why the work is being done; it is to produce specific mitigation of a specific risk.
- A better basis for prioritizing the work. If the work is linked to a specific risk with estimated consequences, it is relatively straightforward to prioritize various projects on a common scale of likelihood of the risk times the consequences.
- A measure of benefits in the form of degree of risk mitigation. Defining and quantifying cost benefits is probably the most difficult component of project evaluation. Using degree of mitigation as a quantified benefit cannot eliminate, but can ease the challenge.
- Elimination of uncertainty surrounding the definition of "safety-related." The stature and priority of real safety incentives are diluted by projects whose safety contribution is not central. Tying the definition to the risk from which the project originates makes the designation more significant.

G. An Approach to Risk

1. Framing a Risk Approach

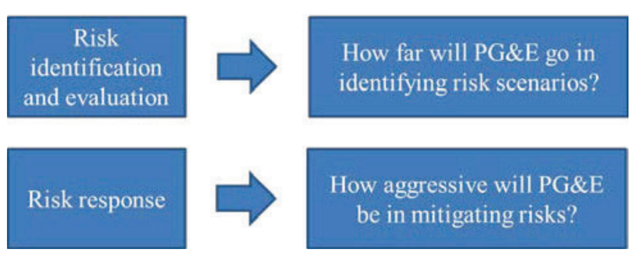
The development and use of risk management grew considerably in the industry in the 1990s, when deregulated wholesale markets demanded knowledge of how to manage commodity-related risks, such as price and credit. The concept broadened later in the industry, becoming known as enterprise risk management (ERM). PG&E has used this broadened concept since 2006. ERM looks at all business risks on an integrated basis. ERM integrates risk management with the normal utility business processes, such as planning, budgeting, engineering, and finance, for example. Risk management in this sense remains a relatively new approach for most utilities. It is common to find some attributes and methods in development. Conversations about risk often produce misunderstanding, differing levels of understanding, differing conceptual approaches, and even differing definitions of the risk management challenge.

The PG&E risk framework includes four main components.

Leadership and governance *Risk monitoring and review*
Risk identification and evaluation *Risk response*

PG&E has used this framework to construct a sound overall program upon that foundation. Management has devoted substantial resources and leadership in originating and sustaining the program. There exists a substantial system for evaluation of risks. It calls upon good tools and techniques. Requirements for response plans are strong, although the effort in actually producing them lags. Moreover, there are appropriate provisions for oversight, although that element of the program is also somewhat lagging.

PG&E is developing the details needed to make its program effective. The accompanying diagram shows two areas (each subject to a wide degree of choice) critical to effective implementation. These are not easy questions to answer and the notion that perhaps the answers will arrive with more experience and some degree of trial and error is reasonable.



The answers to them will define what we call a philosophy of risk. In PG&E's context it is difficult to see how all parties can be on the same page unless and until that philosophy becomes defined and generally accepted.

A consistent level of understanding must first arise within PG&E itself. Following that, establishing a common understanding with stakeholders becomes the next challenge. The questions that arise include:

- Are current LOB philosophies consistent with expectations of senior leadership?
- Are catastrophic risks being passed over or minimized in favor of less challenging ones?
- Are the mitigating actions being taken suitably aggressive?

In the absence of a clear definition of one's philosophical approach, it is difficult to respond to such questions in a structured and programmatic fashion.

2. The Role of Risk in Decision-making

All organizations consider risk in making decisions. We intuitively practice risk management in virtually every element of our lives, generally without much sophistication, or even awareness. The key variable is not whether we assess risk, but how formally and extensively we do. Focusing on these two attributes allows us to form workable definitions of approaches to risk.

Traditional

Risk influences the decision

- **Common sense**
- **May be sub-conscious**

A traditional approach, in the absence of a defined risk-management program

The absence of a formally defined risk program constitutes what we will term a "traditional approach" to management and decision-making. As it applies to public safety, this approach has served and can in many cases continue to serve the technical community well, even absent a formal program of risk management. Traditional risk consideration is informal, and usually based on common sense or judgment (typically engineering in the utility context). No specific risk standards apply; consideration of risk is embedded in the technical judgments one makes on a day-to-day basis. For example, design criteria are established, with risk becoming a function of the conservatism of those design assumptions.

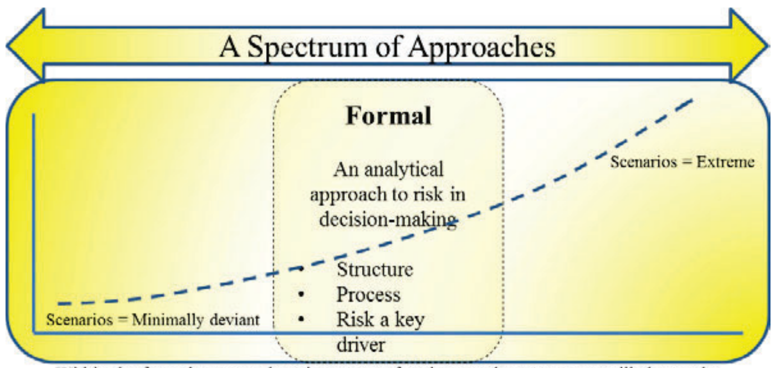
Formal

An analytical approach to risk in decision-making

- Structure
- Process
- Risk a key driver

A formal process elevates the role of risk significantly

Management that observes an increasing role for risk consideration brings greater structure, standards, and visibility to assessing and responding to it. Policies, guidelines, and expectations seek to elevate risk consideration as part of decision-making. Risk becomes a more central driver of decisions and explicit risk analysis becomes being a mandated component of management processes.



Within the formal process, there is a range of options, and management will choose the approach that meets their needs and tastes.

Formal programs elevate the role of risk, but can still exhibit a wide range of approaches. At the minimum end, management might simply use a fine-tuning approach, for example, stretching design criteria by some amount and then analyzing the impacts. Toward the extreme, management might require consideration of very low probability events with extreme consequences. Where one lies between the extremes begins to define a risk philosophy, measurable by the degree to which one stretches the scenarios to be considered.

3. ALARP

In the robust approach, risk is continuously mitigated until it is no longer practical.

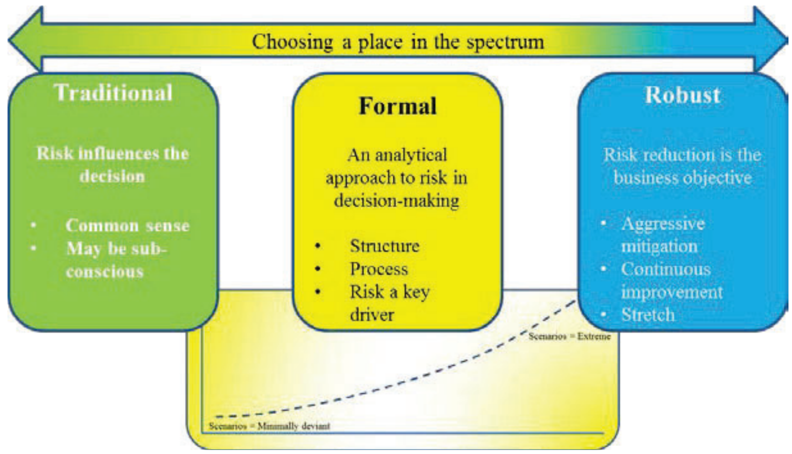
There also exists an additional philosophy that is appropriate under certain circumstances. That approach, which we will call "robust" for purposes of this discussion, gives risk even greater importance, making it the most influential business objective. The goal in such an environment is to reduce risks to a level that is considered "as low as reasonably practicable," or ALARP. In other words, the goal is always to lower risk further until it is simply no longer practical. This approach makes sense for certain business endeavors. For example, in the nuclear industry, there is continuing uncertainty on the part of many concerning the effects of low levels of radiation on nuclear plant workers. Initially, safe levels were thought to be in place, but thinking changed. Even low levels were thought to carry risk. The nuclear solution was to establish the

principle of ALARA (as low as reasonably achievable). That approach continues to be validated in the industry.

ALARP, however, becomes problematic as one moves away from the unique circumstances for which it was originally established. The notion of never being safe enough, or risk-free enough, makes sense in certain specialized industries (like radiation protection), but surely does not apply universally. In addition, the approach is fraught with logistical problems. The "P" (Practicable), is difficult to define, and leaves openings that can undercut the purposes of the approach. In addition, the ability to balance cost and benefits is the lynchpin of ALARP, but such analyses can be extremely difficult to prepare, and are invariably open to substantive disagreement. Finally, it should be clear that such an approach can get very expensive, very fast. The desirability of substantially increasing customer rates in the name of maximizing safety raises its own set of issues. A commonly expressed ALARP notion is that added expenditures are warranted to the extent that the mitigation benefits are not "grossly disproportionate" to the associated costs. That standard would be very troubling for the electric industry. This context has long focused on a group of goals that also includes reliability, customer service, environmental stewardship, affordability and power quality (more recently), for example. Particularly important has been the strong value place on keeping a vital public commodity economically priced.

Nevertheless, there is some level of interest in ALARP in the industry. Of specific interest to Power Generation should be FERC's inclusion of ALARP in its training materials for its proposed new Risk Informed Decision Making (RIDM) initiative for dam safety, although there has been no indication of plans to implement an ALARP requirement in the future.

4. Choosing a place in the spectrum



Settling on a place in the spectrum becomes a matter of an organization's tolerance for risk and business needs. For regulated companies, however, the choice is more complicated. The preferences, tolerance, and needs of stakeholders must also be considered, and optimized through the regulatory process. Without consensus, how the utility and its stakeholders, especially its regulator, can come to a common understanding becomes unclear.

The further left one moves on the above diagram, the more one moves towards minimalist approaches, and tends to fall back into the traditional approach, thereby negating any benefits of the formal program. It serves no good end to operate an elaborate risk program, and then to constrict the nature and extent of the risks considered. This is dangerous for those choosing to operate towards the left side of the spectrum, which we believe includes PG&E, as it traditionally has in the electric utility industry. This assessment will be discussed further under "PG&E's (de Facto) Philosophy."

The matter of "philosophy of risk," or lack of such a defined philosophy, has been a focus of our study. Our discussions with the California Division of Safety of Dams (DSOD) underscore the importance of that focus. DSOD Leadership articulated the view of the risks and consequences the organization should and did confront. They centered on the possibility of a catastrophic dam failure and the potentially large resulting loss of life. There is no question of their "philosophy of risk." It demands focus down to the lowest probability risks. They further apply what might be called "portfolio thinking" to the challenge. This approach means that extremely low probability events must be considered by those responsible for a large portfolio of facilities, such as a DSOD

or a PG&E. Such an approach would tend to push the organization to the events characteristic of the right side of our "formal" box.

H. Summary Responses to the Study's Key Questions

This section provides our overall answers to the questions set forth in the preceding Standards and Criteria of this report.

1. CPUC Expectations

The March 5, 2012 letter from the Commission's Executive Director to PG&E expresses substantially different expectations from those traditional in the industry with respect to the analysis of risk. That letter asked PG&E to include in its GRC Notice of Intent "the "risk assessment that underlies your rate requests." It creates the clear expectation that PG&E will perform a risk assessment, including the safety and security of its electric distribution and generation system, as part of its capital investment planning. The letter expects risk area identification and prioritization. It calls for testimony that "should encompass how safety and security are incorporated into corporate policies, goals, and culture, and the efforts being made to bolster system safety and security." The letter's expectations with reference specifically to testimony are not materially differ from what we have observed traditionally, except perhaps to the degree to which explanation is anticipated. The remainder of these expectations, however, represents a material change from how we have seen utilities explain and justify rate change requests.

Our scope of work for this study includes additional, changed expectations regarding the connection between risk analysis and proposed revenue requirements in the GRC filing. That work scope specifically includes:

- Analysis of the adequacy of PG&E's "use of risk assessment(s) in determining the appropriateness of the level of capital investment funding and Operations and Maintenance (O&M) expenditures"
- Evaluation of "whether the utility analysis includes a credible cost/benefit analysis as the basis for its recommended safety improvement options."

These two work scope elements also create expectations that reflect change in how utility rate change requests have typically addressed safety issues. These expectations require PG&E to move to a leading edge position for the utility industry. The expectations are reasonable, given the need for flexibility in the degree to which they can be accomplished fully, and in the amount of time required to reach a suitable level of accomplishment.

PG&E has been undergoing a notable increase in its management focus on safety. The GRC filing contains substantially greater narrative supporting what represent substantial increases in expenditures for safety. The filing, however, did not demonstrate fundamentally different uses of risk assessment and cost/benefit analysis, although, in the case of Power Generation, did result from a more substantial use of risk assessment in some, albeit not expansive, aspects.

The GRC filing does identify and quantify safety and security spending in reasonable detail, but we found it to overuse the "safety" label. Much of what the Company designates as safety falls under what others consider baseline and reliability work and under what we consider to be more appropriate classifications here as well.

2. Corporate Risk Management and Safety Risk in Operations Planning

PG&E has made substantial enhancements to its risk management program. The Company has expanded what was an industry-representative enterprise risk management program to include a leading edge operational risk management program. This program operates under the guidance of a new board of directors committee, whose charter and operations include regular examination of risk management activities at the corporate and LOB levels. Appropriate executive-level committees oversee risk and safety goals, programs, and results. Risk management falls under PG&E's chief audit executive. His organization includes risk management professionals who provide support for board and executive management oversight. This group also provides process support for the LOBs. These LOB executives must take direct responsibility for operations risk management activities and they have created and staffed organizations to support those activities.

This organization structure devotes significant resources and attention to risk management as a priority. Embedding responsibility in the LOBs, which have responsibility for the operations and activities that produce risk, creates a sound approach, particularly given the top-level commitment to developing its use and guiding its implementation through the use of a corporate level organization. Nevertheless, the goal of meeting the Commission's expectations more promptly would be enhanced by certain, specific changes. First, we believe that retaining executive sponsorship of risk management within the responsibility of the current incumbent would be enhanced by changing his reporting from the CFO to the CEO. The CFO demonstrates clear commitment to enhancing the use of risk management, but the need for advancing cultural acceptance of a fully robust risk management process at the LOB level suggests that its corporate "champion" operate at the highest corporate level. Inseparable from this conclusion is that we believe an independent and effective chief audit officer executive position calls for direct reporting to the CEO. Another beneficial change would be to bring to the corporate ERM organization a person with long and senior utility operations experience. This change would add credibility and therefore "clout" to what is now an ERM organization that (although staffed with capable personnel) is less senior and that is more process than operationally focused.

We believe that these changes will advance what has so far been a notable, but slower than necessary transition from a partial and "test" use of risk management to the robust use that both PG&E contemplates. Our observation is that there remain corporate cultural barriers that slow the process by which the two business units we examined are fully embracing the process. The steady state that PG&E anticipates will include a strongly analytical use of risk assessment. However, it is only now, quite some time from the San Bruno incident (and a year from the March 5 letter), testing a process that will make risk assessment at the enterprise and operational levels a strong contributor to the new integrated planning process that drives PG&E budgeting for capital and O&M expenditures. When fully operational, this process will incorporate leading edge risk assessment at the front end of planning; *i.e.*, before allocation of capital and expense spending. Equally important, this steady state is intended to produce direct and strong linkages at the back end; *i.e.*, risk assessment will be a material driver of integrated operations planning and budgeting, which will directly drive GRC funding requests. This linkage, as designed, has

promise in getting PG&E as far as can be reasonably expected in meeting the regulatory expectations that have focused our work in this study.

While strong and sufficient in concept, much time remains for PG&E to reach its expected steady state. It is only now (April 2013) testing the new risk assessment module of its integrated planning process. Senior executive management's expectations (and we consider them reasonably accurate under current circumstances) are that it will be several years, and perhaps past the next GRC filing, before the process reaches maturity. Interestingly, and of concern, is the more optimistic belief we found among some personnel that the process may be close to fully shaken out by the time the April 2014 risk assessment sessions take place. That belief must reflect an understanding that what is being sought is much less aggressive than what we believe top management actually intends and what the regulatory expectations creates. We recommend that PG&E recognize its needs as including the inducement of both culture change in how the Company assesses and uses risk considerations and a sense of greater urgency in moving toward its expected steady state. These recommendations do not reflect strong criticisms of what PG&E has done so far, recognizing that it is charting new territory for the industry. Rather, they reflect what we believe is necessary to demonstrating a commitment to meeting what we would agree are reasonably aggressive expectations, albeit reasonable stakes to plant in the ground under the circumstances.

These expectations and markers will move the industry forward, raising two important questions:

- How will they play out in the cases of other California utilities
- How will the Commission remain engaged as new territory is charted, lessons are learned, and expectations become calibrated to growing experience?

If changes at issue for PG&E are beneficial, it would appear that others will gain advantage from at least some material part of those changes as well. In addition, sustaining momentum in this area of significant originality will also benefit from continuing stakeholder engagement at times other than GRCs. Moreover, we perceive that the traditional focuses and significant contest of rate proceedings make them a difficult venue for crafting new regulatory approaches or emphases. Thus we consider it likely that creating a formal structure for promoting industry-wide

dialog and sharing of experiences (and experiments even) will go a long way to demonstrating to PG&E and others that risk assessment remains an important objective and that moving the state's entire utility industry forward on a reasonably common basis is significant.

Returning to where things lie now, we observe that, despite material progress by PG&E, it remains the case that one cannot now use PG&E's risk assessments to assess in reasonably robust ways the probabilities and consequences of failures associated with safety and security risks.

3. LOB-Level Safety & Security Risk Management

PG&E has created a structure that will call for its LOBs to use standard and consistent overall risk assessment processes. Corporate and LOB-level organizations, which have created and emphasized common processes, support the development of such processes. There is uneven implementation of them at present, with Power Generation ahead of the Electric Operations distribution segment in developing them. This gap stands to reason, given the external and organizational environment in which Power Generation operates. That environment includes the very heavily safety-regulated nuclear power environment and the lesser, but still substantially safety-related hydro facility environment Liberty's study focused on hydro operations in PG&E's Power Generation LOB. Nevertheless, while progress has been made in both groups that we examined, April 2013 will begin an important test of a more robust use of risk assessment in planning, and top management appears keen to use that learning process to continue moving to the steady state it anticipates for linking risk assessment ultimately to GRC proposed funding levels.

PG&E has generally assessed the physical condition of its system (both physical assets and supporting systems) adequately, but exceptions in Electric Operations include the need for greater attention to cause assignment for system incidents and events and for the adoption of a more formal asset management approach. Assessment of safety and security risks is moving in both LOBS we examined toward a more structured, quantified risk assessment process that seeks to incorporate more quantitative assessments of probabilities and consequences, and to identify a

more robust range of mitigation measures and their costs and benefits. Both have ground to cover, as the later, more specific discussions associated with each address.

In neither case did we find the efforts of these two units substantially deficient with respect to what we have observed in the industry. We did, however, find in the case of electricity distribution instances where the state of its infrastructure has not kept pace. On a related matter, we believe that aging infrastructure makes this issue an important risk even apart from strict safety concerns, although we do see a connection between the reliability issues such infrastructure imposes and potential safety consequences. PG&E's infrastructure is probably in some respects newer than that of other utilities, whose conditions make this issue one, in our view, of significant nationwide consequence. However, as PG&E's senior leadership observes in GRC testimony, the Company recognizes that historical levels of expenditure and current system conditions make this an issue here. Our scope did not include an examination of the reliability and quality issues that serve as a principal driver of the aging infrastructure issue. Nevertheless, our observations of and about the system from a safety perspective lead us to agree that addressing aging infrastructure through a long-term program appears to be an important priority. We particularly noted the issue in our work associated with the distribution system, but the age of PG&E's hydro assets makes the issue pertinent there as well.

We did observe an increased emphasis on safety expenditures as proposed both for Power Generation and electricity distribution. We observed a greater use of risk assessment by the former in advance of the GRC, but for neither of the two units could we observe clear and strong connections between risk assessment and GRC budgeting for projects and programs. We did find in both cases that project and program emphases do address clear safety issues, and that the expenditures appear designed to mitigate properly identified and material safety risks.

4. Risk/Revenue Requirement Nexus

We were able to identify what GRC capital and O&M projects and programs PG&E identified by applying safety and security considerations. We found that an overly liberal use of the "safety" tag applied -- no doubt influenced by the focus on safety created by the March 5 letter and other circumstances. We did what we could to isolate those programs that in our judgment

were truly driven predominantly by safety and security concerns, as opposed to other factors, such as reliability, compliance with other public requirements, or simply consistency with sound baseline utility operations.

Having made this categorization, we could not identify any that PG&E had founded explicitly on structured, analytically founded risk assessments. Our conclusion in this regard was supported by the acknowledgement of senior LOB leadership that engineering and other professional judgment formed the basis for deciding what initiatives to pursue and at what levels of proposed expenditure. We queried PG&E about it's the adequacy of its foundation for concluding that expenditures to address safety and security and security risks are in proportion to risks properly identified. We could not find substantial documentation of this type of thinking or analysis, although we consider such support to be consistent with the expectations created by the March 5 letter and by the areas of inquiry included in our scope for this study. We, like PG&E, consider those expectations to be appropriate under the circumstances, and are cognizant of the fact that substantially satisfying them will "advance the ball" from an industry-wide perspective, will take time, and will likely require modulation based on experience gained as time moves forward.

We also did observe a measurable way of determining on a quantitative basis, from the work that PG&E has shared with us, the extent to which those projects and programs can be expected to reduce identified risks. Similarly, the Company has not demonstrated analytically that the benefits of proposed safety and security risk mitigation measures justify their costs. We asked PG&E specifically about such analyses. The response was that none had been prepared to support the GRC as filed. We learned that relevant documentation may now be under preparation. We trust this is so, but find it surprising that, a year after the March 5 letter, it remains incomplete. We, like others, will presumably have to await responsive PG&E evidence in the GRC to determine the relevance and address the substance of that documentation.

Given the circumstances, we could not assess whether the degree of risk reduction can be expected to reach a level considered satisfactory from customer, public, and employee perspectives. Nor could we apply any PG&E risk assessments to determine the appropriateness of related projects and programs and of the costs associated with them. As our report makes

clear, however, we do generally believe (fairly narrow exceptions are noted in this report) that PG&E has tailored specific and responsive GRC projects and programs to known and reasonably identified safety and security risks. Moreover, those projects and programs are reasonably designed to mitigate those risks.

5. LOB-Specific Conclusions – Power Generation

The Energy Supply LOB has responsibility for internally-owned generating facilities and contracts for power. It includes Nuclear Generation, which operates the Diablo Canyon plant, but our study scope excludes that area of operations. We focused on Power Generation, which operates all of the non-nuclear, PG&E-owned generation. From a safety perspective hydro operations are the most significant of Power Generation's assets; they were our primary focus. Power Generation's GRC-proposed capital and expense spending levels are both more than 30 percent higher than the corresponding 2012 levels. One cannot accurately define which portion of the spending goes to safety and security projects because of the lack of a satisfactory definition. However, it is clear that a large share of the increase relate to projects categorizable as safety-related under any reasonable definition.

The Power Generation organizations have made significant strides in addressing safety in the past two years. Power Generation's development and implementation of a risk assessment process has led to: (a) an extensive review of infrastructure, leading in turn to (b) a large amount of physical work to mitigate safety risks associated with, among other things, aging facilities. Supporting this physical work have been technical analyses, particularly by the Power Generation Asset Management organization, as well as implementation of numerous risk assessment tools that have helped focus priorities.

Power Generation is relatively more advanced than Electric Operations (for electricity distribution) in the use of risk assessment processes. The tools and techniques of PG&E's program are sound, and, in principle, reflect best practices. It is not clear, however, that these tools (for example the Risk Evaluation Tool) are being used to their full potential. Risk scoring and ranking occur, but we did not observe substantial use for them in prioritization efforts. Power Generation uses a process of "alternatives analysis" in seeking mitigation options,

presenting assessments of feasibility, implementation barriers, schedule for implementation, cost of implementation, and the degree of risk reduction expected. This process is sound, but appears to be used more to report on decisions already made, rather than to support decision-making itself.

Large dams do not lack for attention. Power Generation makes extensive use of consultants and outside panels. Regulators are active in meeting their oversight responsibilities. In addition, safety criteria and regulatory oversight tend to grow with time, producing an element of continuous improvement in terms of managing and lowering risks. We found no reason to question the effectiveness of dam safety management; it is strong and growing stronger.

As is true for electricity distribution, Power Generation should operate on the basis that aging infrastructure rises to an enterprise-level risk. Many components of the hydro system are at an advanced age. This feature presents real risks for things "wearing out," particularly recognizing that standards by which old facilities were built are often inferior to current standards. In addition, improving Risk Response Plans (RRPs) should be a priority for Power Generation. Energy Supply set a goal of issuing only one such plan in 2012, but did not meet it. The one RRP goal has been extended to April 2013, with the balance of operational risks due by the end of the third quarter 2013. Power Generation needs a more aggressive approach to completing these plans.

Liberty examined the question of how Power Generation conducted for the GRC the process of "drawing the line" on spending at some appropriate level. We sought to determine how it decided what aggregate level of spending makes the most sense and which proposals to delete or defer. We were unable to identify how that process was conducted or, more importantly, what rationale governed the final choices. In addition, the combination of the GRC process and Power Generation's internal workings make it unlikely that the projects that actually will get done in 2014 will match the GRC list very closely.

We identified the need for modifying the planning process in the future to: (a) provide allowances for new and carryover work, and (b) provide the list of projects that are proposed to

be deferred if less than requested funding is granted by the CPUC. Such an approach will go a long way towards creating a much-improved understanding of the work that can be accomplished. It will also provide a more realistic base from which to monitor performance against plans. A similar need exists in the case of electricity distribution. On a related issue, we believe that there should also be a process for providing to the Commission, regular reports of amounts actually spent, supported by analysis and explanation of variances.

We did conclude, after reviewing projects and expenditures by Power Generation category that the GRC projects and programs proposed do address important safety risks. Specifically, we determined that: (a) the elevation of priorities in Power Generation has been appropriate, (b) the nature of the projects is consistent with the needs of the system and the new priorities, (c) the technical development of projects is strong and they are suitably justified and of adequate quality, and (d) while linkage to risk assessments remains limited, a picture of how linkage can and should work in the future has emerged and the vision seems to be absolutely attainable. The one major question hanging over all of this is the aggregate level of spending, whose rationale and justification remain clouded.

In summary, we believe that the proposals will mitigate observable safety risks; however, we also concluded that Power Generation needs to provide improved justification and rationale for the proposed aggregate level of expenditures for safety initiatives. The proposed increase in spending is substantial, especially when viewed as increases in safety-related spending. The GRC, however, lacks a rationale for why the chosen aggregate spending levels are appropriate and how they were determined.

The issue of public safety has an appropriate place in Power Generation's hierarchy of priorities. There is a Public Safety Officer, whose staffing will be augmented by two additional people. A new comprehensive public safety program has been created. Public safety metrics and benchmarks are not in widespread use; many of the hazards posed by Power Generation's facilities are unusual. Nevertheless, Power Generation continues to work on development of such metrics. There has also been a substantial increase in safety emphasis at the corporate level. However, what once was an improving trend in incidents has turned more negative.

In the area of emergency management, Power Generation structures its approach around the National Incident Management System (NIMS). Power Generation people are trained and drilled in this approach and are well-versed in its requirements. Power Generation maintains close coordination with local emergency management responders. Power Generation has extensive experience and capabilities in emergency management and no issues are apparent.

6. LOB-Specific Conclusions - Electricity Distribution

The reorganization of responsibility for electricity distribution and the creation of a Distribution Asset Strategy and Reliability have increased focus on distribution infrastructure issues affecting safety. Electric Operations, however, does not yet operate a formal asset management program addressing its distribution system. We recommend the establishment of one. These types of programs force a detailed and thorough condition assessment survey of the major assets, and take failure modes into consideration. Long term sustainable plans can then be prepared to address the asset conditions. A sustainable asset management will mitigate system safety risks from aging infrastructure, which constituted a major portion of the safety items in this GRC.

We also recommend particularly for the electric distribution that PG&E treat aging infrastructure as an enterprise-level risk. Aging infrastructure is an issue for U.S. utilities and industry in general, in both the government and privately owned spheres. It is too easy and it has been too common for utilities to put off the replacement to reduce new investment. As replacements are delayed, the magnitude of the financial implications of getting behind becomes too severe to overcome. Safety risks can also develop. The primary tool for avoiding this pitfall is a strategic infrastructure plan that addresses all major assets.

Several aspects of the PG&E distribution system present significant safety issues for the Company:

- The unigrounded 12,470 volt three-wire system that serves as the predominant 12 kV configuration. Very few utilities use similar three-wire systems. They cause downed lines often to remain energized until a dispatched PG&E Troubleman can respond on site.

- PG&E employs about 22 thousand miles (approximately 20 percent of primary voltage overhead distribution conductor) of obsolete #6 copper. The small size of this once popular conductor makes it comparatively more subject to breakage as it ages.
- PG&E also has 47,542 miles of #4 Aluminum Conductor Steel Reinforced (ACSR) conductor on its distribution system. Corrosion issues make this conductor no longer recommended for use in coastal areas.

Issues such as these also present significant reliability issues. There exists in electricity distribution a very significant overlap between reliability and safety issues. In many cases, reliability concerns should drive enhancements before safety concerns become critical. However, PG&E, like the rest of the industry, faces substantial aging infrastructure issues. We did not undertake an independent analysis of the system from this perspective. The evidence of PG&E's CEO, however, acknowledges the problem, and those observations we did make in performing our examination of system safety issues support a concern about this issue.

The use of risk analysis extends beyond safety. It is important that PG&E also use it to address reliability and safety (among other goals, such as customer service and environmental stewardship). The Company needs to do so in a manner that allows risks associated with all applicable goals to be analyzed, prioritized, and addressed through appropriate initiatives in a balanced manner. The longer a utility takes to address aging infrastructure, the more reliability and safety issues emerge, and the more difficult it becomes to support initiatives in a manner that maintains a sustainable rate trajectory. We believe it is important for the Commission to assure that, as focus on safety increases, the need for addressing infrastructure from the reliability and rate trajectory perspectives remains at the forefront as well.

Through 2011, formal consideration of electricity distribution risk took place under an overall ERM program that, like the programs of most utilities, focused primarily on top corporate risks, but did not apply structured, comprehensive analysis of operating risks. In 2011, following the San Bruno incident, Electric Operations changed its approach to considering risk along two tracks:

- Employing PG&E's expanded ERM program to incorporate more structured consideration of operational risks.
- Forming the Electric Operations Improvement Plan, which has not incorporated formal risk assessment, but which has generated a focus on immediate actions that could mitigate known risks.

Activities under the first part of the revised approach have been proceeding, but not at a rapid pace. The charter for the Electric Operations Risk & Compliance Committee came in November 2012, followed in December by the LOB's first register of key operational risks, with the items listed still under evaluation. Through the preparation of the GRC, the Electric Operations Improvement Plan, which is not founded on structured risk assessment, has served as a driver of initiatives to mitigate safety risks. The Improvement Plan, however, does explicitly address projects and programs designed to address public and employee safety.

Electric Operations is just now reaching a foundational milestone in the use of more structured operational risk assessment. It has just completed (for use in senior management Operations Planning sessions scheduled for this April) its draft Risk and Compliance (formerly called "Session D") templates. These templates do chart some risks on the basis of probabilities and consequences, but in a partial and preliminary way. Quantification of probabilities and consequences flowed from a judgmental process, only a fairly small number of operational risks have been included, and there is no layered approach that considers a range of potential mitigation measures and levels of effort (and accompanying costs and reductions in risk). The template does not support an analytical approach to identifying the costs and benefits of a range of mitigation measures.

Both senior executive and LOB management consider this April's Risk and Compliance sessions to represent a test case for implementing a more analytically based consideration of risk and including it as an integral part of Operations Planning, which drives budgets, and in turn future GRC filings.

We analyzed the distribution expenditures detailed in PG&E's GRC Exhibit 4. We did not agree with the Company's identification of those that can be considered "safety-related," as we would define the term. We asked PG&E to reclassify expenditures according to our structure. Many of the electric distribution initiatives in the GRC comprise fairly straightforward infrastructure replacement projects. For the vast majority of them, like-for-like replacement is the only feasible alternative, making replacement timing the predominant variable. Over 88 percent of the identified GRC system safety initiatives consist of replacing aging infrastructure and adding SCADA capability. This result conforms to the stated direction of the Electric Operations Improvement Plan. We also found that the electric distribution safety initiatives comprise main contributors to increased costs above 2011 levels. While identified safety initiatives constitute less than twenty percent of the electric distribution GRC items, they represent increases of over 300 percent from 2011 expenditure levels. By contrast, items associated with reliability, base operations, and support show an increase of about twenty percent over recorded 2011 expenditures.

GRC Exhibit 4, Chapters 2-4 addresses a number of technology safety initiatives. They were not derived from or supported by structured risk assessment or cost/benefit analysis. They will contribute to mitigating system safety risks by addressing gaps in asset records, information management systems, and emergency response. The degree to which they do so cannot be determined from the GRC or from other information made available by PG&E.

GRC Exhibit 4, Chapter 5 addresses distribution maintenance initiatives. They too were not supported by structured risk assessment or justified by analyses of their costs and benefits. However, with one exception, we found them to be sound programs that appear to be effective and properly managed programs that mitigate identified safety risks. Those that we found effective were those addressing:

Preventive maintenance patrol and inspection
Enhanced wildfire patrol
Infrared inspection
Underground oil switch replacement
Underground enclosure barcode
Network high-rise transformer replacement
Network CBM
Network SCADA
Swiveloc manhole replacement

The exception involves conductor replacement under the infrared program. Portions of that replacement program compete with rather than complement the conductor replacement in Exhibit 4, Chapter 15.

We did not find the initiatives of GRCV Exhibit 4, Chapters 6-8 to be driven by structured risk assessment or cost/benefit analysis, but they generally represent appropriate and effectively managed responses to underlying safety issues. These initiatives include the wood pole inspection and maintenance program and the vegetation management program. We also found that the fire risk reduction program could potentially reduce wildfire risk. The American National Standards Institute (ANSI) published a new standard for tree risk assessment in late 2011. PG&E has modeled its program after this voluntary, best-practices standard.

Again, we did not find underlying risk assessments or cost/benefit analyses for substation assets, and reliability initiatives addressed in GRC Exhibit 4 – Chapters 13 to 15. We did, however, find those programs to be contributors to mitigating safety risks, subject to several concerns.

We found the substation asset strategy programs to be effectively managed. We observed no unaddressed safety risks. We also found that the conductor replacement program addresses a serious safety issue. Its ultimate costs, however, are likely to extend well beyond the amounts reflected in the GRC. The impacts of conductor failures are magnified by the large percentage of downed conductors that remain energized. Electric Operations has yet to assess fully the magnitude of the deteriorated conductor situation. The forecast levels for the Chapter 15 replacement did not follow a sound assessment of system conditions.

We also found the unit costs of Chapter 15 replacement to be high. The main cost driver appears to be the lack of identification of a suitable replacement conductor. Rather than replace the conductors with equivalent ampacity wires, divisional engineers have often installed upgraded feeder conductors, such as 4/0 aluminum. More effective program controls are in order.

PG&E's two different conductor replacement programs appear to compete with, rather than complement each other. The Chapter 5 Maintenance conductor program looks for three splices in a span. These splices will generally only occur when the conductor has had past breaks. The Chapter 15 Reliability conductor replacement program targets conductors on the primary basis of outage history. This history also tends to identify conductors that have often been spliced. It would be more appropriate to make the infrared and associated splice registry strictly an identification program rather than replacing conductor one span at a time.

7. Response to Specific Engagement Questions

The scoping documentation for our study contains seven general questions relating to the overall technical adequacy of PG&E's work addressing safety matters in this GRC. They are discussed throughout this report, but we respond to them here in overall summary form.

Will the projects reduce risk to ALARP levels? No. ALARP is not a criteria for PG&E's risk and mitigation program, nor do we necessarily see suitable opportunities for its application. Further study of specific, limited applications would be as far as might be recommended at this time.

Do projects have a credible cost/benefit analysis? No. Costs and project justifications are included in the work papers, but a credible CBA is not. We emphasize that CBAs are problematic in areas such as safety – they are neither easy nor are they typically fruitful. This does not mean they should not be addressed when practical.

Was the physical condition of the system adequately considered? It was exceptionally so in Power Generation. The asset management work was excellent and what started as a good effort was accelerated further on multiple occasions. The same was not so in electric distribution in the case of deteriorated conductors. PG&E has not yet fully assessed the extent of this condition.

Were projects linked to a risk assessment? Generally, no. Some projects do flow from the ERM hydro risk, but the path is not a straight line.

Were a prudent set of alternatives considered for each project? There is generally no record of such consideration.

Will projects reduce risk and enhance safety? Yes, without question.

Can the degree of enhancement be quantified? No. As with the cost/benefit issue, this is a difficult question to answer; although there is some potential here for use of the Risk Evaluation Tool (RET) for this purpose.

II. Corporate-Level GRC and Risk Processes

A. The Operations Planning Process

PG&E's Operating Planning process underlies its GRC filing. This process embeds current and planned use of risk analysis to the extent relevant for GRC purposes. We examined the nature and degree to which safety risk assessment underlies PG&E's current GRC filing. The "Operating Planning" process has served as a primary driver of safety-related spending following the September 2010 San Bruno incident. The process has changed since that time and its operation this year is bringing an increased focus on the consideration of risk in plan development. The evolution of the process is important in understanding the risk-based underpinnings of the current GRC, and how those underpinnings may change in the future.

1. Operating Planning for 2011-2013

PG&E's Operating Planning processes have served as the principal source of budgeting. The operating plans have included a one-year budget and two additional plan years. This planning regime was in effect during 2011 and 2012; *i.e.*, the first two planning years following the San Bruno incident. Significant incremental safety expenditures occurred during these years. The rates in effect during these two years were the levels authorized in the Company's 2011 GRC, settled in May 2011.

PG&E recognizes the authorized levels of capital expenditures and operating expenses in place from the previous GRC case in its operating planning. The Company manages to these levels of expenditures in its annual operating plan or budgeting process. The operating plan is usually based upon capital and operating expenses near the indicative authorized levels from the GRC, with a general goal of earning the authorized return on equity for the relevant budget year. Operating plans build from the bottom-up for each LOB, based upon work plans developed in each area. An operating plan committee (OPC) consisting of the president and CEO, the CFO and the vice president finance and planning serves as the governing body that receives and authorizes the bottom-up budgets from each LOB. The operating plan process concludes with an approved final budget and "budget letters" to each LOB that officially authorize specific

spending levels for each area. The proposed budgets are presented to and approved by the Company's Board of Directors at their December meeting.

a. 2011 Planning Cycle

The PG&E operating planning process for the 2011 budget year began shortly after the September 2010 San Bruno incident. Budgeting was to be performed using a new prioritization process and budgeting template. The Company had declared a deadline of 2014 for achieving the vision of becoming the "leading utility" in the United States. PG&E defined leading utility as first quartile performance for "energized employees" and for "rewarded shareholders," and first decile performance for "delighted customers" and environmental leadership. Twenty-five key drivers to reach these four goals served as 2011 focus areas. The planning focus was the 2011 budget year, with the following two years of the three-year operating plan to be constructed in early 2011.

The LOBs developed their 2011 requests based on the planning guidelines and templates and prioritization requirements. No CPUC decision on the 2011 GRC had yet occurred. The originally approved 2010 budget thus served as the original generalized target for capital and operating expense spending levels. Planning guidelines specifically instructed the operating LOBs (Electric and Gas Transmission and Distribution, Customer Care and Energy Supply) to prioritize projects and amounts above 97 percent of 2010 budget levels. All non-operating units were to prioritize above 93 percent of their 2010 budget level. Work and spending below these levels was not required to be prioritized. Safety was not then a "top 10 goal." The CEO had also yet to issue his 2011 request for "turnaround plans" related to safety from the operating LOBs.

PG&E's 2011 budget levels for expenses were about $37 million more than the regulatory authorized levels. Capital expenditures were budgeted at $2.355 billion, or about $115 million greater than regulatory authorized targets. PG&E spent significantly greater than both budgeted and authorized regulatory levels for both capital and operating expenses in 2011. According to the Company, the greatest amount of incremental capital expenditures occurred in gas transmission related to San Bruno and in gas distribution and customer care. The Company also cited higher storm activity as requiring more spending by Electric Operations. Some electric

2011 spending was reallocated following the establishment of an Energy Supply turnaround plan and an Electric Operations improvement plan during the second half of the year.

The next table shows that PG&E spent $21 million more in 2011 than the regulatory authorized level for expense, and $16 million less than budgeted. PG&E spent $264 million more capital dollars than the regulatory level and $148 million more than budgeted.

2011 Budgeted vs. Actual Expenditures

2011 BUDGET VS. ACTUAL EXPENSE BY LINE OF BUSINESS
2012 BUDGET BY LINE OF BUSINESS
(MILLIONS OF DOLLARS)

		Expense					Capital				
Line No.	Line of Business	2011 Imputed Regulatory Targets	2011 Budget	2011 Actual	Budget vs. Actual (%)	2012 Budget	2011 Imputed Regulatory Targets	2011 Budget	2011 Actual	Budget vs. Actual (%)	2012 Budget
1	Gas Distribution	$680.0	$144.7	$153.5	6.1%	$221.7	$1,435.1	$251.6	$302.7	20.3%	$380.2
2	Electric Distribution		535.0	553.6	3.5%	553.2		1,162.5	1,225.6	5.4%	1301.3
3	Customer Care	450.8	433.4	427.1	-1.5%	470.9	101.3	106.0	108.4	2.2%	136.3
4	Nuclear Generation	328.8	309.4	313.0	1.2%	336.6	133.9	211.9	233.5	10.2%	260.6
5	Power Generation	193.9	181.0	169.2	-6.5%	193.5	173.8	238.2	258.7	8.6%	268.6
6	Energy Procurement	60.5	54.0	50.4	-6.6%	52.0	–	–	–	–	–
7	Support Orgs and A&G	575.7	651.8	643.5	-1.3%	689.7	395.0	384.5	374.0	-2.7%	506.3
8	Subtotal	$2,289.6	$2,309.3	2,310.3	–	2,517.6	2,239.2	2,354.6	2,502.9	–	2,853.3
9	Reserve	–	17.1	–	–	52.4	–	–	–	–	–
10	Total	**$2,289.6**	**$2,326.4**	**$2,310.3**	**-0.7%**	**$2,570.0**	**$2,239.2**	**$2,354.6**	**$2,502.9**	**6.3%**	**$2,853.3**

Notes: 1. 2011 imputed regulatory targets for gas and electric distribution are combined to be consistent with previously reported information in the 2011 GRC.

The Electric Distribution organization overspent its 2011 expense budget by $18.6 million, or 3.5 percent. The largest drivers were increases in underground inspections and storm-related emergency service restoration work. Electric Distribution overspent its 2011 capital budget by $63.1 million or 5.4 percent. Increases were primarily driven by higher than planned WRO projects and higher-than-planned units of work for overhead conductor replacement, breaker replacement, and overhead maintenance.

The Power Generation organization underspent its expense budget by $11.7 million or 6.5 percent. Power Generation's capital expenditures were $20.5 million or 8.6 percent greater than budgeted, largely due to increases in safety-related and regulatory projects. These increases were partially offset by delays in FERC license issuance and related project work and a reduction in capital work at the Helms power plant.

b. 2012 Operating Planning Cycle

The 2012 planning cycle differed from that of the previous year. Planning and forecasting for the years 2014 through 2016 for the next GRC filing was to be initiated as part of this process. The processes commenced with the issuance of planning guidelines in August 2011 as part of Quarterly Business Review #2 (QBR2). This first set of guidelines and instructions focused on the 2012 budget year, but also requested from the LOBs plans for 2013 and 2014. The plan and forecast for the three years was to be established first; GRC planning was eventually separated from this initial effort and refined for the rate case period on its own path and separate process.

The QBR2 planning instructions took a general nature, especially when compared with planning instructions for the previous and following years. The bottom-up plans from the LOBs were to include "plan work, resources, and budget" sections. Each LOB had to define a business overview, its initiatives, their alignment with 2012 to 2014 goals, the major work initiatives and programs to be completed over the next three years, key performance indicators and LOB metrics, and an update on enterprise risks falling within each LOB. ERM risk analysis would not finish prior to the September 2011 due date for the work plans. The Company's formal operating risk management processes and techniques had not been developed or rolled out at this time. The reference in the planning instructions was to enterprise risks that each LOB "owns."

Each LOB's plans also had to include a resource section identifying the specific workforce strategy for each LOB. Proposed budgets were required to show significant changes from the 2011 original budget. LOBs presented requested funding for 2012 through 2014, along with the prioritization methods used and the risks associated with funding levels below the 2012 request. The utility strategic plan, "Road to 2014" goal drivers, the enterprise risk management template, and 2012 and 2013 preliminary capital and expense targets served as reference materials.

The resulting operating expense forecasts through 2014 and capital expenditure forecasts through 2016 came in September and October of 2011. For 2012 planning, Electric Operations and Energy Supply submitted multi-year financial outlook documents. These documents included 2008-2010 actuals, 2011 budgets, 2012-2016 initial requests, and various year-over-year

comparisons at the program and major work category (MWC) level. October 19, 2011 budget letters set total GRC expenses of $2.306 billion and capital expenditures of $2.863 billion.

c. Conclusions

PG&E planned for and actually spent above its rate case authorized capital and expenditure levels in 2011 and 2012, partly to improve public and employee safety. PG&E used rate-authorized levels of capital and operating expenses for the years 2011 to 2013 as set in its 2011 GRC. However, the Company spent more than its rate-authorized levels during the past two years following the San Bruno incident.

PG&E's approved 2012 capital expenditures budget was $445 million above rate-authorized levels, and $800 million of capital spending above authorized levels is planned for 2013. PG&E's financial results in 2011 and 2012 have been poor, with 2013 projected to be even worse than the previous two years.

PG&E's normal practice with regard to budgeting is to target its annual spending levels near its GRC-authorized levels. Doing so allows a return on equity near authorized levels to be attained. However, the San Bruno incident and the following IRP and Blacksmith Group reports changed this dynamic for 2011-2013. Capital and operating expenditures driven by safety responses in the operating LOBs increased in 2011. The safety "turnaround plans" for the LOBs requested by the CEO in mid-year 2011 increased safety and security spending for 2012 and beyond.

2. 2014 GRC Planning Process

a. GRC Process and Guidance

PG&E's 2014 GRC sets revenues to fund electric and gas distribution, utility-owned generation and corporate service organizations' operating and capital costs for the years 2014 through 2016. PG&E files a GRC application every three years to apply to successive three-year rate periods, such as 2011-2013 and 2014-2016. The CPUC's rate case plan sets the requirements for the rate case processes of each of the state's major energy utilities.

PG&E's 2011 Quarterly Business Review #3 ("QBR3") provided the planning instructions and guidelines for the GRC. This information provided a starting point for developing the GRC

forecast for 2014 through 2016. The QBR3 guidelines asked all units to "take a critical look at their expected activities and the cost of those activities," using the information to update the 2014 forecasts that had recently been completed through the QBR2 process.

The QBR3 forecast used the 2012 budgeted amounts that had been approved in October 2011 and the 2013 "preliminary targets" developed in the same process as foundations for developing the GRC forecasts. The instructions noted that, "Forecast amounts for 2014 should reflect each organization's best professional judgment and are not constrained based on previous forecast or target amounts." The guidelines anticipated that the first version of forecast submissions would be entered into PG&E's systems in December, and then undergo refinement and adjustment until April 2012. This timeline would allow GRC witnesses time to use final GRC forecasts to update their testimony and supporting work papers for a planned Notice of Intent (NOI) filing in July 2012 and a GRC application by December 2012.

Each organization received planning templates requiring the following information for use in the GRC forecast and filing:

- A multi-year financial outlook for expenses (2012-2014) and capital expenditures (2014-2016)
- Year-over-year "financial walks" (identifying sources of changes) from the 2011 original budget to the 2014 expense and 2016 capital forecasts
- Year-over-year financial walks by GRC exhibit and chapter
- Cost/benefit analysis for "new types of work"; a template and guidance were to be issued later in 2011
- A year-over-year headcount walk for corporate services organizations.

A cost benefit analysis requirement had arisen from the 2011 GRC Order. New types of GRC-proposed costs were to include in the revenue requirement estimated cost savings to be achieved or an explanation of why there would be no cost savings. LOBs received a project summary template addressing cost savings explanation. Project justifications included categories of "cost savings" and "cost avoidance." Another template section addressed non-cost benefits, *i.e.*, operational safety and reliability and environmental benefits a project would produce.

Responsibility to assure provision of the required analysis was left to management of each LOB, which received training, the templates discussed above, and a decision tree.

The next table shows the template for Electric Distribution capital. The other LOBs had to present a similar financial outlook for use in developing the GRC Forecast.

Electric Distribution GRC Template

(Amounts shown are pre-tax, millions of $)

	PROGRAM / MWC	HISTORICAL			2011		2012-2016						COMPARISONS						RATE CASE		
		2008 Actuals	2009 Actuals	2010 Actuals	2011 Budget	2011 YE Forecast	2012 Forecast/Request	2012 Prelim. Target	2013 Forecast/Request	2014 Forecast/Request	2015 Forecast/Request	2016 Forecast/Request	2012 Request vs 2011 Budget	2012 Request vs 2012 Prelim. Target	2013 Forecast vs 2012 Forecast	2014 Forecast vs 2013 Forecast	2015 Forecast vs 2014 Forecast	2016 Forecast vs 2015 Forecast	GRC	TO	GT&S
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N) = (H) - (F)	(O) = (H) - (I)	(P) = (J) - (H)	(Q) = (K) - (J)	(R) = (L) - (K)	(S) = (M) - (L)	(T)	(U)	(V)
1	Capacity & Reliability																				
2	6																		x		
3	46																		x		
4	8																		x		
5	49																		x		
6	56																		x		
7	Capacity & Reliability Total																				
8																					
9	Maintenance																				
10	7																		x		
11	57																		x		
12	2A																		x		
13	2B																		x		
14	2C																		x		
15	Maintenance Total																				
16																					
17	Automation & Protection																				
18	9																		x		
19	63																		x		
20	Automation & Protection Total																				
21																					
22	Emergency Response																				
23	17																		x		
24	95																		x		
25	Emergency Response Total																				
26																					
27	New Business & WRO																				
28	10																		x		
29	16																		x		
30	30																		x		
31	NB / WRO Total																				
32																					
33	Substation																				
34	48																		x		
35	54																		x		
36	58																		x		
37	59																		x		
38	Substation Total																				
39																					
40	Support																				
41	12 - Environmental																		x		
42	5 - Support																		x		
43	78 - Buildings																		x		
44	2F - IT Projects																		x		
45	Other MWCs																		x		
46	Support Total																				
47																					
48	**Total for Electric Distribution**																				

b. GRC Forecast Refinements

The first version of the GRC forecast came before the GRC steering committee in late January 2012. This committee includes the CEO, CFO, and all other senior PG&E officers. The first version of the GRC forecast presented an "opportunity for the LOBs" to propose what they considered to be required spending during the 2014-2016 rate period. This first version included total 2014 LOB expenses of about $2.959 billion, or an increase of 25 percent from 2012 authorized levels. Electric Distribution expenses would increase by 11 percent and Energy Supply expenses by 27 percent from the 2012 levels. Proposed total capital expenditures for 2014 of $4.055 billion would produce an increase of 72 percent from 2012 levels. Electric

Distribution capital expenditures would increase 32 percent and Energy Supply 104 percent. The increased capital and operating expense levels would result in an overall rate increase request of about $1.6 billion. After review with the GRC steering committee, the CEO requested that the GRC request be scaled back to result in smaller rate increases.

Subsequent versions of the GRC forecast (GRC updates) came before the GRC steering committee thereafter. The forecasts became "locked down" for all LOBs except Gas Distribution by March 29. The only changes made to the electric requests after the March 29 version involved moving IT projects from the IT LOB to the operating organizations. Gas distribution continued to update forecasts after March 29 until June. The final GRC request proposed a rate increase of $1.230 billion, or about 18 percent overall. During the GRC forecast revisions, Electric Distribution's requested expenses increased by an additional $17 million and capital expenditures an additional $44 million. Energy Supply's requested expenses decreased by $39 million and capital expenditures increased by $7 million.

The following GRC forecast information comes from the May 29 Update meeting. This information changed only slightly prior to the NOI filing, except for Gas Distribution.

May 29, 2012 GRC Forecast

LOB Expense ($ millions)	2013 Authorized	2014 Forecast	Increase from 2013 Authorized
Electric Distribution	$580	$631	9%
Gas Distribution	251	470	87%
Customer Care *	435	464	7%
Energy Supply **	626	723	15%
IT	215	262	22%
Shared Services	97	103	6%
Corporate Services ***	240	289	20%
LOB Expense Total	**$2,444**	**$2,942**	**20%**

Capital Expenditure ($ millions)	2013 Authorized	2014 Forecast	Increase from 2013 Authorized
Electric Distribution	$1,337	$1,716	28%
Gas Distribution	272	840	208%
Customer Care	112	189	69%
Energy Supply	317	636	101%
IT	119	212	78%
Shared Services	195	247	27%
Corporate Services	2	65	-
Capex Total	**$2,355**	**$3,906**	**66%**

The GRC included projects and spending from the Electric Operations "Improvement Plan" and the Energy Supply "Asset Management Public Safety Acceleration Plan." PG&E developed these plans following the June 2011 release of the CPUC's IRP report. During the GRC forecast refinements, PG&E focused on ensuring inclusion of safety investments from the Improvement Plan and the Energy Supply Plan. The Company announced a "Back to Basics" program in March 2012. This program included an increased emphasis on safety and safety investments. This program occurred too late to affect the GRC forecast. Nevertheless, PG&E maintains that the Improvement Plan and other turnaround efforts from 2011 were factored into the spending increase requests of these LOBs included in the GRC forecast.

c. GRC Forecast - Timing

The focused development of the GRC forecast kicked off with the QBR3 instructions and guidelines issued in mid-November 2011. A rough draft forecast that included the years 2014-2016 was first produced in December. This forecast was refined and presented to the GRC steering committee at least three times from January through the end of March 2012. The GRC forecast was "locked down" for the electric LOBs and the support LOBs as of March 29, 2012.

The chart below shows the timing for GRC Forecast development. The Electric Operations Improvement Plan and the Energy Supply asset management public safety acceleration plan would each have been completed in ample time to be included in the GRC forecast.

2014 GRC Forecast Development Timing

The building of the GRC forecast began in November and December 2011 and was completed and locked down for the electric and support functions at the end of March 2012. The CPUC Executive Director's letter addressing PG&E's use of risk assessments in identifying safety and security initiatives and spending for GRCs was dated March 5, 2012.

d. Conclusions

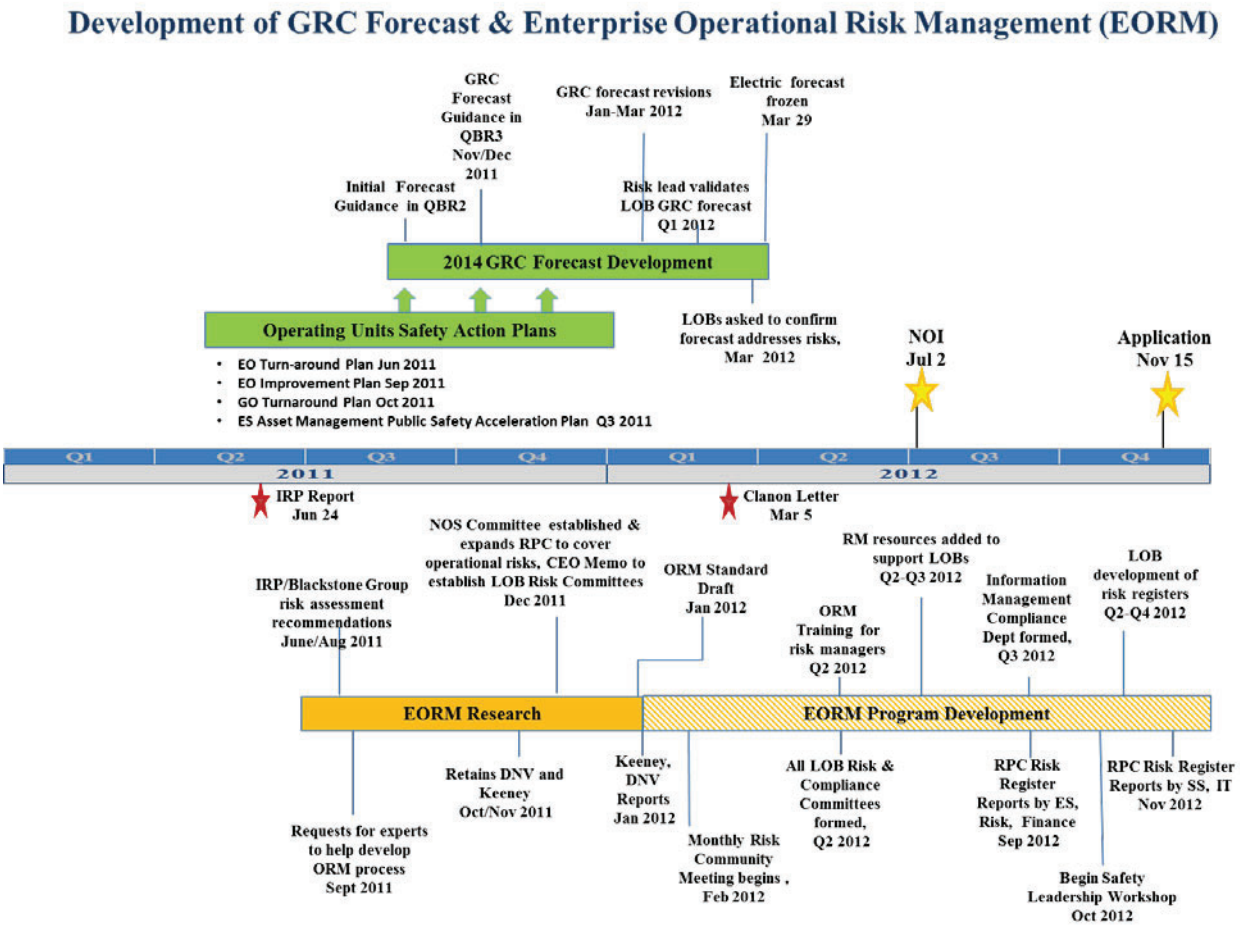
PG&E's 2014 GRC filing for electric and support services reflects the status of planning and safety and security programs as of the first quarter of 2012. The building of the 2014 GRC forecast began in November and December 2011 and was completed and locked down for the electric and support functions at the end of March 2012. Specific and focused development of the GRC forecast kicked off with instructions and guidelines issued to the LOBs in mid-November 2011. A rough draft forecast including the years 2014-2016 first came in December. Subsequent refinements, following input from the executive-level GRC steering committee, came from January through the end of March 2012. The GRC forecast was "locked down" for the electric LOBs and the support LOBs as of March 29, 2012.

The previous chart shows the timing for GRC forecast development. The Electric Operations Improvement Plan, the Energy Supply asset management public safety acceleration plan and the GO Turnaround Plan, each of which has a safety focus, provided inputs to the GRC forecast. The March 5 letter came too near the end of GRC forecast development to permit it to be substantially considered on the NOI filing schedule.

The Company identified the specific actions it took in response to the March 5 letter in the immediate context of the GRC forecast. Those actions were limited to adding risk policy testimony and reviewing the existing forecast and testimony to ensure that it addressed operating risk management and identified risk gaps. As a result, the 2014 GRC does not include structured and quantified risk assessments as a basis for developing capital and operating expense requests. Risk assessment processes that drive work plans and safety and security spending were researched in 2011, developed in 2012 and are just being integrated on a test basis into the planning cycle taking place in 2013 (as discussed in the following section of this report).

PG&E developed its GRC forecast from November 2011 through the end of March 2012, as shown above. The development of the risk assessment of corporate processes began with research and "preliminary steps" following the IRP and Blacksmith Group reports in the summer of 2011. As of March 2012, PG&E had received operational risk management reports from consultants DNV and Dr. Keeney, formed Board, executive and LOB risk committees, and drafted an ORM standard. Training for risk managers in ORM and taking the first steps in risk assessment for the LOBs, such as identifying risks in a risk register, were to occur later in 2012. Risk assessment processes were early in their development processes in 2012. They had not advanced sufficiently to form a part of the planning processes, as acknowledged by Company executives. The risk and compliance session scheduled for early April 2013 will be the Company's first attempt at using risk as part of the integrated planning process.

The following chart compares the timing of the GRC process versus development of operating risk management at PG&E.



We also conclude that top-down spending limits did not constrain the development of the 2014 GRC capital and expense forecasts in general nor specifically those related to safety and security. The planning guidelines for this effort did not include any spending levels, limits or targets that might constrain the LOBs in the building of project and spending requests. When the results of the bottom-up forecast were reviewed by the CEO and the GRC Steering Committee, they asked for the total spending be scaled back somewhat, to lower rate increase percentages. On the second iteration of the forecast, the Electric Operations and Energy Supply "turnaround" plans were referenced, and the LOBs were asked to review any additional safety spending, to remove any unnecessary costs and to find operating efficiencies to a greater degree.

Total spending for electric capital expenditures and operating expenses showed little total change from the first GRC forecast iteration in January 2012 to the forecast included in the GRC request. During the GRC forecast revisions, Electric Distribution's requested expenses increased by an additional $17 million and capital expenditures by an additional $44 million. Energy

Supply's requested expenses decreased by $39 million and capital expenditures increased by $7 million. A portion of the revisions were due to reassigning IT capital and expenses from the IT LOB to the other LOBs.

The 2011 Electric Operations "Improvement Plan" and the Energy Supply "Asset Management Public Safety Acceleration Plan" focused on safety drove incremental GRC electric capital expenditures and expenses for 2014-2016. The GRC included safety and security projects and spending initially proposed in the Electric Operations and the Energy Supply "turnaround plans" that were developed following the release of the CPUC's IRP report in June 2011.

Liberty did not observe a substantial level of quantification of cost for safety and security related projects and programs initiatives proposed in the GRC. For the most part, cost savings for these initiatives were not quantified. PG&E instead focused primarily on narrative justifications of the projects; *e.g.*, defining reasons requiring the expenditures and addressing qualitatively the sort of consequences that could occur in their absence.

In Electric Operations, cost savings from project initiatives were quantified on a limited basis for a few of the major project categories. For instance, a major project category for infrared inspections totaled over $77 million of capital expenditures from 2014 to 2016, and about $13.5 million in annual operating expenses. PG&E quantified expenditures avoided from outages due to this significant investment in capital and expense dollars of about $1 million per year in operating expenses and about $1 million per year in capital. Another major investment in underground switch replacement of over $75 million from 2014 to 2016 included estimates of $200,000 per year in cost avoidance due to failed underground oil switches. The distribution network's SCADA safety monitoring new program included investment of approximately $38.5 million over a five-year period from 2012 to 2016. Estimates were made of about $3.5 million per year of reduced transformer maintenance costs and smaller amounts of other avoided costs due to the investment. This investment had significant quantified cost savings that could justify it on a cost/benefit basis. Overall, these examples from electric distribution show limited cost savings estimates on these major investments. For other areas such as large capital or

investments in support services (such as the Alternative Emergency Operations Center for about $20 million), we did not observe cost savings calculations in the project justifications.

Liberty recognizes the cost savings benefits are difficult to quantify for many types of utility investments. Quantified cost savings for most utility investments that are not "discretionary" are very difficult, and often are not significant or comparable to the investment costs as performed in a traditional cost/ benefit or economic analysis. We recognize this limitation in performing such analysis. However, the quantification of as much cost savings or other benefits as possible is useful to utilities as information that may be used in the prioritization of projects. The more information that is provided regarding realistic and quantifiable cost savings or benefits, the higher relative priority that an investment should have due to its demonstrable benefits. While such cost-saving information is only a portion of the total picture in justifying projects, more information is useful in prioritizing the projects both within an LOB and between business units.

3. PG&E Operating Planning – Future State

a. Integrated Operating Plan Adoption

The IRP report provided PG&E an impetus to change its planning systems and processes. The report was critical of PG&E's strategic planning and its budgeting processes. The Company came to understand that its quarterly business review processes used to manage planning were overly finance-oriented, and based on inflexible templates. The overall intent was to change the planning dynamic to become more operationally oriented, and to spring from specific strategies and goals through work plans.

Company executives visited DTE (Detroit Edison) in November 2011 to observe planning processes that DTE based upon a General Electric planning model. PG&E's new CEO (formerly CEO at DTE) believed that the benchmarking and strategy that drove planning there was effective, and resulted in good financial discipline. Company representatives also visited General Electric to discuss the GE planning processes. PG&E decided near the end of February 2012 to adopt an "integrated planning process" based on the GE model. PG&E first used this new process in March 2012 to build plans for a 2013-2015 planning horizon. The effort to develop the new integrated planning process came shortly after construction of the 2014 GRC forecast.

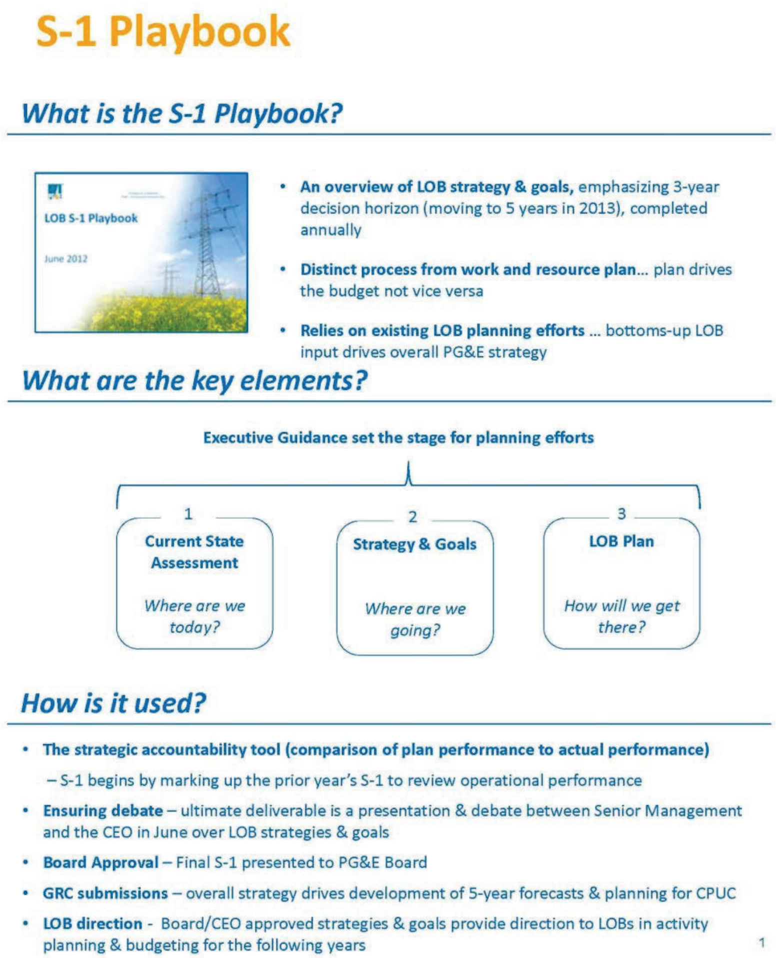
PG&E's introductory presentations and materials for the new integrated planning process described it as follows:

- CEO-led effort to implement a multi-year planning process modeled on GE best practices and utilized successfully at DTE
- Separated strategy from work and resource plan: rigorous strategic planning drives execution
- Bottoms up-planning and debate: incorporates input from officer direct reports and discussion between CEO and senior management in June regarding strategies and goals; September execution
- The ultimate deliverable is a single company plan for managing performance.

The Company highlights a number of differences between the new and previous planning process. One of the most important is to separate strategic from execution planning, and to allow strategy to drive the allocation of human and financial resources. Strategy and plan drive the budget, and not the reverse. Planning for strategy, work plan execution, and the allocation of resources previously had occurred concurrently, as part of the same process.

PG&E also sought under the new integrated planning approach to make the LOBs, rather than the finance team, the drivers of the process. Each LOB would develop its own bottom-up planning through a process engaging its officers and managers. LOB strategies and goals eventually approved by senior executive management and Board of Directors would provide direction to LOBs in activity planning and budgeting. The intent of the integrated planning process is to manage the Company to "one plan" with all other planning activities, including the GRC, integrated into this process.

The integrated planning process also extends the PG&E planning horizon from three to five years (starting in 2013), and makes GRC efforts a subset of the integrated planning. Budgeting takes a detailed one-year view that will also comprise a subset of the integrated plan. So-called "Session 1 (strategic playbook)" and "Session 2 (work and resource planning)" form key components of the integrated planning process. Session 1 consists of an overview of LOB strategies and goals emphasizing a five-year decision horizon. Each LOB assesses the external

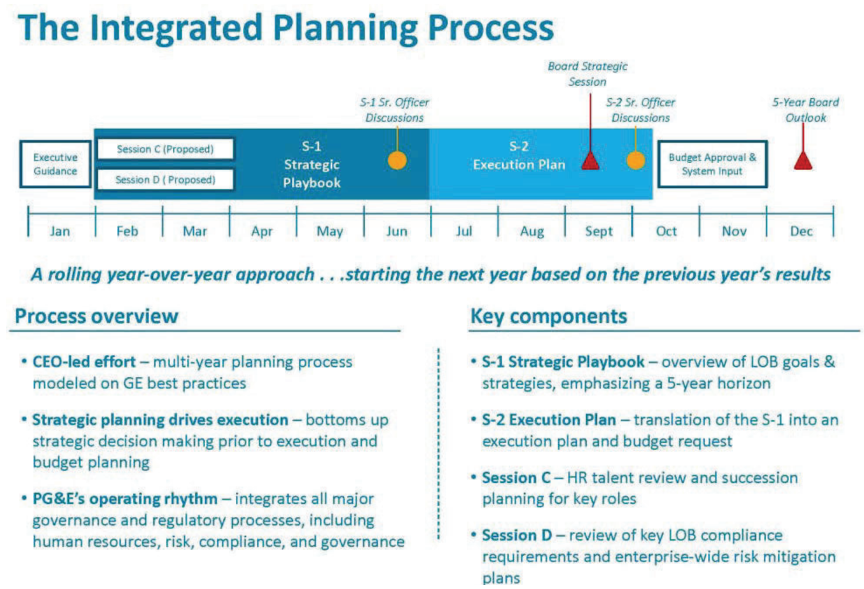


and internal factors that help or hinder its plan, examines current performance, and compares to unit benchmarks for top quartile performance. The business units then develop a strategy and goals for the next three to five years to address closing the gaps in their benchmark performance. An LOB strategic plan is then developed to reach each LOB goal, close the gaps in benchmarked performance, and determine the key metrics and milestones that will be tracked to measure performance.

Annually issued executive guidance kicks off the development of S-1 strategic playbooks. For 2012, targets for public and employee safety were provided for new electric metrics such as incidence of wires down, 911 emergency response, lost workday case rate, preventable motor vehicle incidents rate, and a SAIDI reliability target. Quartile performance targets for the year-end were also provided.

A key input to the development of S-1 strategic plans was originally termed "Session D," which addressed development and assessment of LOB compliance requirements and governance factors that influence strategy. PG&E's plans for "Session D" have evolved to include (beginning with planning work in 2013) risk assessments and mitigation as drivers of input to S-1 strategies for each LOB. Formalized risk assessment processes were being developed, structured and rolled out at PG&E during 2012, as we will discuss later.

The next chart graphically describes the annual integrated planning process and how the process should flow when fully developed. Note that initiation of the integrated planning process in March 2012 means that the Sessions C and D inputs were not in place to inform development of the S-1 and S-2 execution plan during 2012.



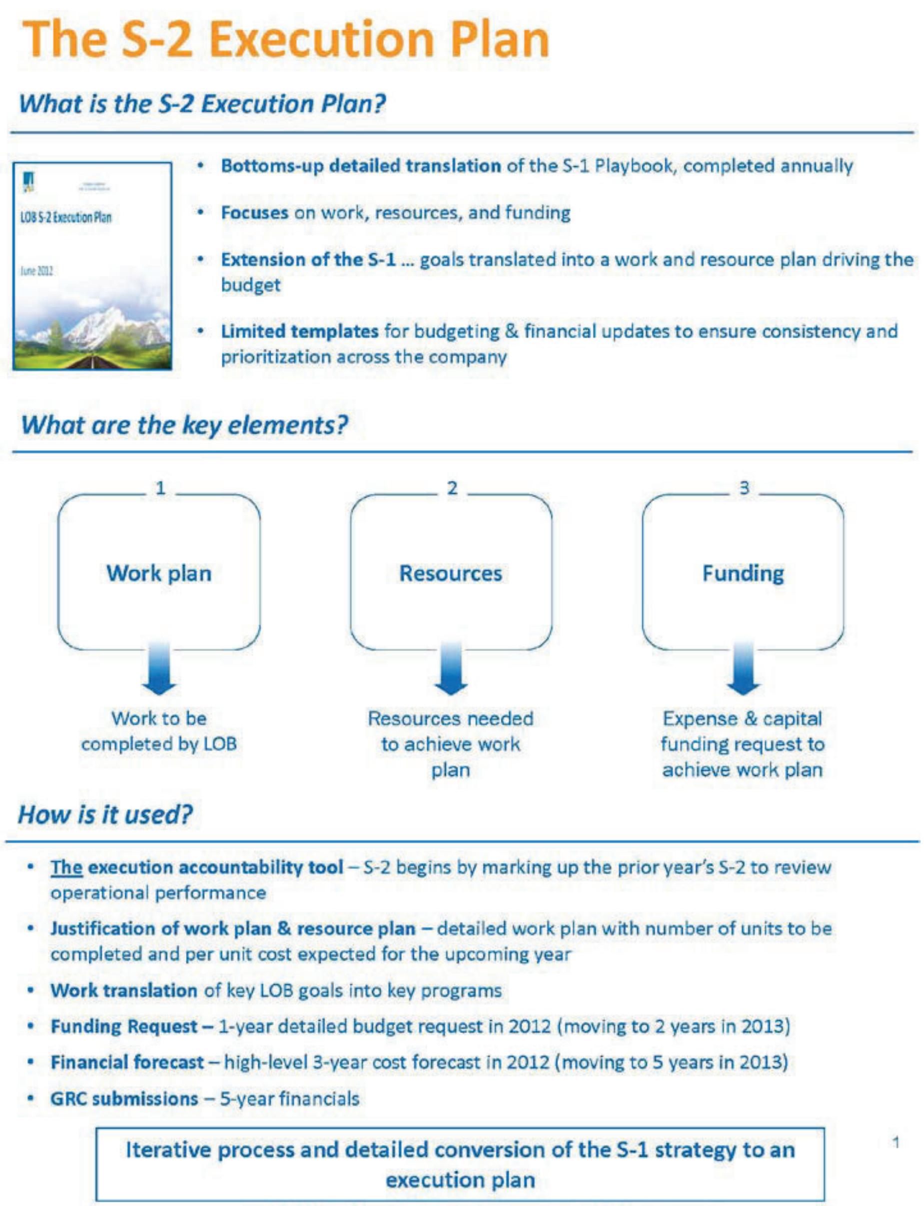
The S-1 strategic playbooks for each LOB are developed and presented to senior officers for discussion in June of each planning year, as shown above. The PG&E 2013 strategic playbook (corporate) was then presented to the Board of Directors in September 2012.

The S-2 process is a second primary component in developing the integrated plan that follows the S-1 process and utilizes its results as a starting point. The S-2 is termed an "execution plan." This plan translates the strategy and goals developed in the S-1 to key programs, focus areas and resources required. The LOB programs and focus areas are internally assessed to first determine work plans with key programs, expected performance versus the previous year and against benchmarks, and expected benefits over the planning horizon. The LOB work plan is to address the mitigation of potential risks or capitalize on opportunities identified in the S-1.

Each LOB also determines the funding required to support its work plan and resources. Drivers for significant year-over-year changes in funding required are to be identified. The key risks associated with deferring or eliminating work are also to be assessed. Methods for prioritizing work projects and programs used to determine a funding level request should be clearly defined and utilized. The LOBs are also required to compare the capital and operating expense requests

in the planning process (in this case for 2013 through 2015) with the 2014 GRC forecasts for the same years, to confirm their alignment.

Unit work counts and unit cost targets are determined that result in a detailed work plan and the accompanying financial resource needs, including capital and expense estimates. Spending is then to be linked to operational gains and improvements prior to the development of specific capital and expense requests for each LOB. The Company's description of the S-2 execution plan is shown below.



LOB S-2 plans will undergo development in the July through September timeframe. The LOBs will then present them to senior executive management in early October, with budget approval anticipated by the end of November each year. Board of Directors presentations and approvals are scheduled for December Board meetings. A (highly confidential) five-year "Financial Outlook" covering the years 2012 or 2016 was also prepared and presented to the Board of Directors in December 2012. The financial outlook summarizes PG&Es financial performance and metrics through 2016, based on the three-year integrated plan for that year and views varying assumptions such as authorized and earn rates of return, timing of the resolution of the GRC and levels of incremental capital and expense spending. A five-year financial outlook of this type is common in the industry as a high-level financial overview and summary for the Board of Directors.

b. 2013 Integrated Planning Process

The integrated planning process is evolving in early 2013. What was formerly termed "Session D" is now termed the "Risk and Compliance Session." The LOBs completed in mid-March drafts of risk assessments intended to undergo discussion including senior executive management at early April sessions. These just-developed risk assessments will feed development of S-1 strategies for each LOB through early June. This will be the first time that risk assessment and compliance action plans will feed and drive the S-1 and S-2 processes. The initial 2012 integrated planning process did not benefit from structured risk assessment input.

The risk assessments developed for use in the April sessions are not complete. For example, the Electric Operations document considers a fairly small subset (albeit what the LOB considers a set emblematic of its most significant risks), and uses a judgmental process for identifying likelihood and consequence. Senior leadership considers these sessions to be more a test of the session process than a comprehensive set of structured risk analyses. Experience gained in the coming sessions may bring significant change in their use and in the risk information underlying them. In any event, senior leadership anticipates certainly one and likely several subsequent yearly cycles to conclude before the process reaches a mature stage. The uncertainties affecting this maturation process include both: (a) how the sessions consider and end up driving plans, and

(b) the ability to move the LOBs to full acceptance, understanding, and use of a more structured, analytical, and comprehensive risk assessment process.

In any event, the long-term goal is to link risk management to strategy development and resource prioritization through these processes on a formalized and structured basis. The 2013 cycle will be the first integrated planning process in which this process will be tested. PG&E recognizes that the 2013 integrated planning process is the "first time through" the entire process and that more developed risk assessments with more refined risk quantification will occur in future years.

In January 2013, the PG&E CEO issued his 2014 executive guidance to kick off the integrated planning process. The guidance included goals addressing regulatory commitments, customers, employees and investors. The executive guidance set forth:

- A safety performance goal of first quartile in the industry by 2014 and top decile safety performance by 2016
- First quartile operational performance by 2015 and top decile operational performance by 2017
- A goal to "ensure that the capabilities exist to continually monitor key operational risks and comply with regulatory directives"
- A goal to engage with regulators to achieve positive outcomes in rate cases
- Customer goals including achieving second quartile JD Power customer satisfaction results by 2014, first quartile by 2015 and top decile by 2017
- Goals for customer affordability, alignment of overall rate increases consistent with the GRC, and keeping future rate increases at or below inflation
- High-level employee goals including generating top quartile engagement results in the 2014 Premier Survey
- Investor goals of earning the authorized ROE by 2014 (excluding gas transmission), preserving balance sheet strength, and maintaining corporate credit ratings.

c. Conclusions

Risk assessments employing robust quantification of probabilities, consequences, and mitigation opportunities will happen in 2014 at the earliest. Using such assessments to drive capital and

O&M planning and budgeting will not occur before that time. The LOBs will first document and present their individual Risk and Compliance processes and results to senior executives in early April 2013. The current process is the first of its kind at PG&E. How far this year's process will go in establishing a "baseline" that may be built upon in future years is an open question in the minds of senior executive management. Management hopes that next year's risk and compliance session will "use risk and compliance information to allocate resources" in its process overview, but there is not a strong level of optimism regarding attainment of this goal that early. The linking of quantified risk assessments to strategy development in the S-1 planning process and to resource prioritization in the S-2 planning process does, however, represent an ultimate goal and "end state" of the overall risk assessment structure, as viewed by senior executive management.

Company executives recognize that the risk and compliance sessions are a "work in progress," and that the current process will be a key test in measuring progress. Executives express uncertainty about when the risk assessment process will reach its steady, expected state. They point to the large amounts of data and the analytic rigor that must develop to permit risk assessment to take a comprehensive and significantly more quantified form. It is reasonable to conclude from what executive management believes and what we have seen that it will take at least three years to arrive at this point. In other words, while the 2014 risk assessments will be further refined, they will not be a finished product. It is fair to conclude that significant PG&E concern exists with respect to setting expectations too high regarding the "vision" to quantify risk and use it to allocate resources.

B. PG&E Risk Assessment Development

1. Risk Assessment Drivers

The IRP report concluded that PG&E should acquire and develop a staff of professionals with the skills necessary to do state-of-the-art practical analysis of risk management decisions that concern public health and safety, employee health and safety, environmental consequences, socioeconomic consequences, and financial and reputation implications for the Company.

PG&E began an effort in 2011 to research and develop risk assessments for use in planning and resource allocation. This process did not produce major, evident changes in the use of such

assessments in the current GRC filing. Nor has the Company completed since that filing any structured analysis of risk in relation to its GRC proposals. The subject of risk clearly received substantially increased discussion in the GRC. Moreover, the Company has continued to advance its consideration of risk, but has not made specific changes to the 2014 GRC forecast to incorporate the structure and the connection between risk assessment and proposed GRC expenditures.

The Executive Director of the CPUC advised PG&E in the March 5, 2012 letter that:

> *… "PG&E should include as part of your upcoming Notice of Intent to file a GRC the risk assessment that underlies your rate requests."… and "PG&E should provide testimony to identify and prioritize areas of risk and include the underlying rationale for your assessments."*

Our engagement, foreseen by the March 5, 2012 letter from the Executive Director, addressed this expectation, setting as part of our scope an evaluation of:

> *the adequacy of PG&E's use of risk assessment(s) in determining the appropriateness of the level of capital investment funding and Operations and Maintenance (O&M) expenditures*

Our scope in performing this review included an evaluation of "whether the utility analysis includes a credible cost/benefit analysis as the basis for its recommended safety improvement options." We similarly found in response to our inquiries that the GRC filing did not provide substantial cost/benefit justification for the particular levels of expenditure that its GRC proposes for safety-related projects, programs, and initiatives. We understand that the Company is preparing additional information of this type, but it was not available for our review before completing this report.

2. Risk Assessment Research

PG&E established an enterprise risk management process in 2006, at a time and in a manner that comports with our experience. Its ERM program had elements common in major utility companies:

- The program identified 10 to 12 major or catastrophic risk items (generally these are not safety-related risks)
- A general examination of consequences and mitigation efforts identified
- Assignment of each major risk was to a corporate officer "responsible" for managing it
- Refreshment of the ERM assessments on a two-year cycle.

PG&E assigned two employees to manage the ERM program.

The IRP, along with a Blacksmith Group report commissioned by the Company, stimulated the development of more thorough and wide-ranging corporate risk assessment processes. It moved ERM well beyond the initial level typical of the industry. As relevant to our review, this new approach sought to make operational risks an integral part of ERM. It did so by seeking to embed the primary processes in operational risk identification and response in each LOB, operating under the direction of top LOB leadership, and carried out through dedicated resources. PG&E also strengthened its corporate level ERM resources through providing process-based encouragement, guidance, and support. This enhancement reflected a sound effort to move risk management from its traditional, ERM base, which focused predominantly on a fairly small set of top-level risks, among which financial and reputational risks tended to dominate over operational ones.

However, and this is important from the perspective of the March 5 letter and our scope, the research and development of a structured, Company-wide risk assessment program, as recommended by the two reports, was only beginning at this time. It would not keep pace with the development and filing of the current GRC.

In October and November 2011, PG&E retained the services of Det Norske Veritas ("DNV") to develop a framework for an enterprise and operational risk management program. The Company

also hired Dr. Ralph Keeney to provide input to this framework. By the end of January 2012, both DNV and Dr. Keeney had provided reports on a "system safety risk framework." In December 2011, a PG&E board created a Nuclear, Operations, and Safety Committee and expanded the charter of the Risk Policy Committee (RPC) to cover operational risks. Shortly thereafter, the PG&E CEO, before the two consulting reports, instructed executive and senior vice presidents to form LOB risk and compliance committees and to hire risk managers to review all operations and processes and associated risks. The PG&E Chief Risk Officer took responsibility for developing corporate risk assessment processes and providing guidance and support to LOB efforts, from within his Risk and Audit organization. These actions represented the kick-off of PG&E's development of a corporate-wide, structured, operational risk analysis processes.

3. Risk Assessment Development

The development of risk assessment corporate processes continued throughout 2012, but their development lagged the schedule for NOI and GRC filings. The Risk and Audit organization drafted an Operational Risk Management Standard in early 2012. The PG&E RPC approved it in late March. The standard has set the following direction, which embeds the basic risk management structure:

Effective risk management includes five key elements:

1. Leadership – the overall approach to governance; effective risk management performance indicators; and accountabilities, responsibilities and authorities for risk management.

2. Risk identification and evaluation – the process for identifying and analyzing issues that could threaten strategic objectives, company goals, business processes, and/or company assets, determining the level of risk, and prioritizing risks.

3. Risk response – the process of developing an appropriate response strategy to address a risk.

4. Risk monitoring and review – independent verification of control effectiveness; and analyzing and learning lessons from events, near misses, changes, and trends.

5. Change management – plans to insure risk management activities are changed in a controlled manner.

The ORM standard assigned to the Chief Risk Officer responsibility for developing corporate risk management standards, providing oversight of risk management activities, and reporting to the Board of Directors and its committees. The Chief Risk Officer also has responsibility for facilitating a risk management process that covers all LOBs, provides risk assessment and mitigation support to LOBs, and for managing the corporate RPC agenda to ensure adequate executive review. The executive vice presidents and senior vice presidents of each LOB have been given the responsibility and the obligation to perform the detailed work necessary for identifying and managing the risks within their organizations. They must define responsibilities and authorities for risk management, identify a risk manager and perform the structured risk-management activities that the corporate standard imposes. Separate LOB risk managers have responsibility for coordinating all risk management activities analysis and risk mitigation within their organizations and are expected to work with Risk and Audit to ensure corporate consistency of approach and conformance with the standard.

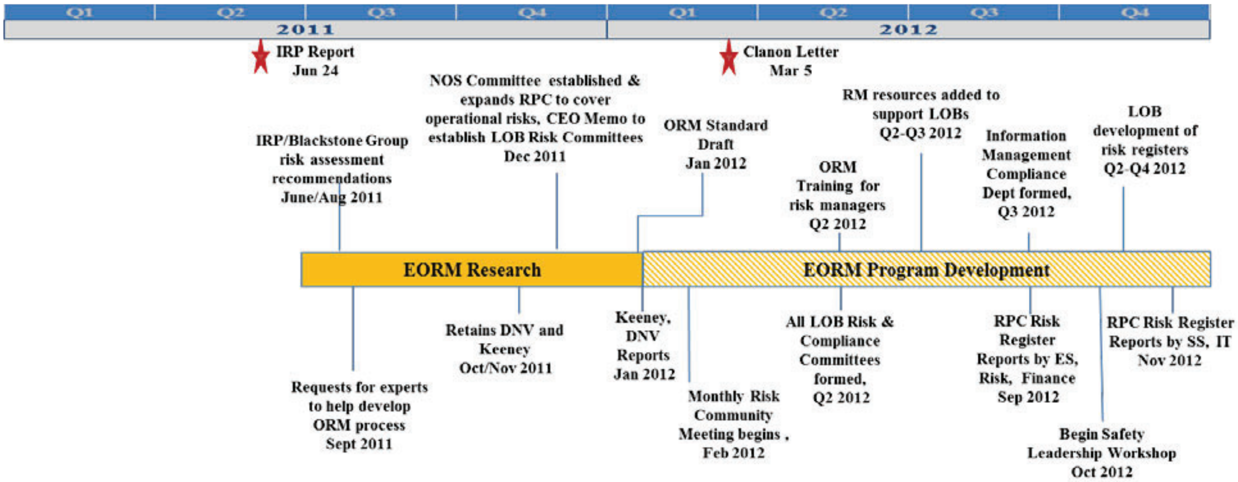
The Risk and Audit group developed criteria for evaluating risk and a generic risk assessment evaluation tool for use by the LOBs as a guide to assess and score risks. A risk register template was also developed to sort the risks and report them to the RPC. Guidance documents prepared for the LOBs included a "starter charter" for risk management, a risk register template, information flow graphs, risk identification criteria, a risk assessment and evaluation tool (spreadsheet), risk register templates, guidance regarding analysis of alternatives, and resources for assistance. The goal of the risk assessment team is to blend subject matter expertise in the LOBs with outside risk expertise hired by the Company through a teambuilding effort.

The Risk and Audit group has sought to stimulate LOB engagement in robust risk assessment and management processes. This year, the goal (which PG&E will test at the April 2013 planning sessions described earlier) will be to provide format and structure that can be used to identify, rank, and present alternatives for mitigating risks both within the LOBs and across them on a consistent basis, as part of the Integrated Planning Process. This process feeds the development of strategies, execution plans, forecasts and budgets, which PG&E intends in the

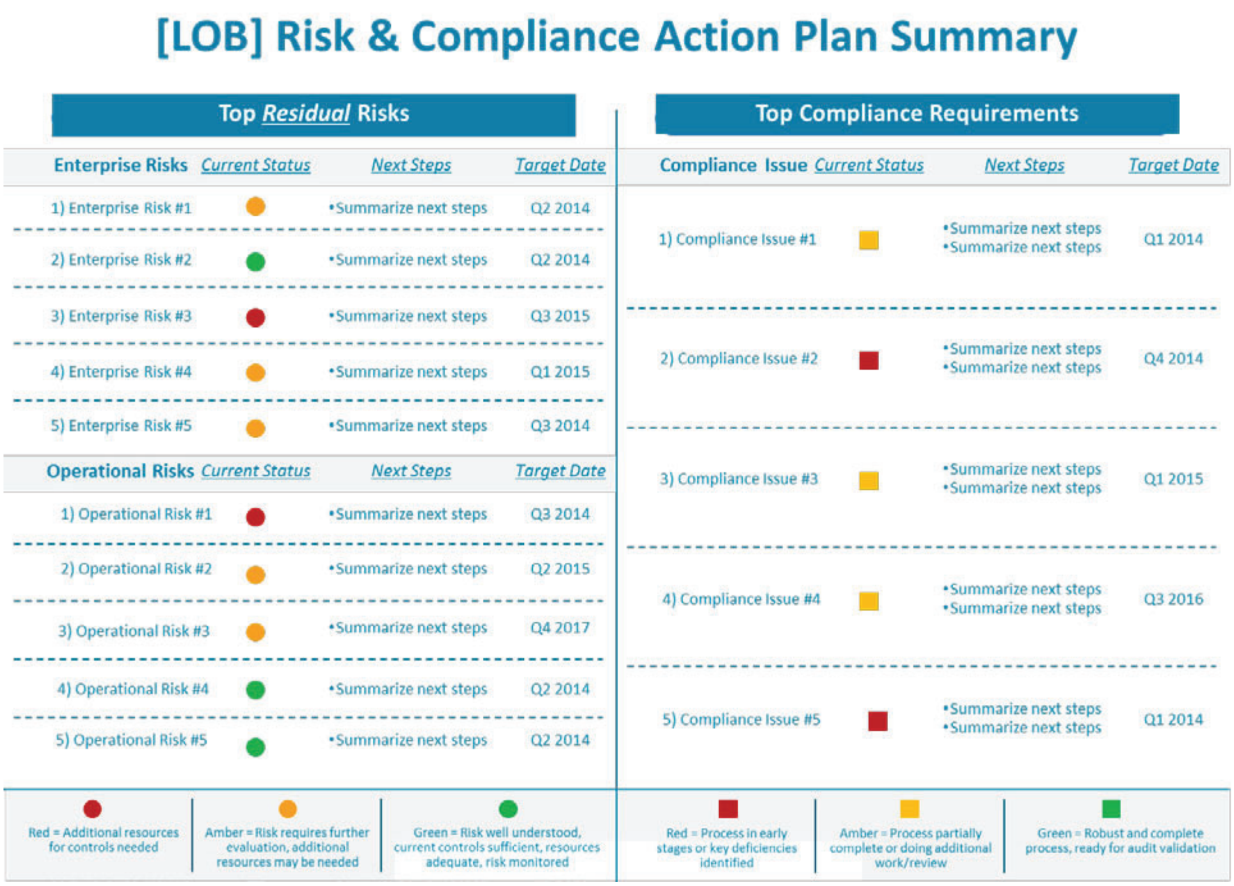
future to drive GRC planning and preparation as well. The risk assessment structure is intended to be a medium to move toward a long-term vision of risk that will be attained over time, but is not expected to reach a steady state until after what senior leadership sees as a multi-year process.

A target date of the end of the first quarter of 2012 was set for hiring risk managers and holding initial LOB risk and compliance committee meetings. A two-day operational risk management training class for LOB risk managers was held in April 2012, with a half-day follow-up in May. A goal of identifying top operational risks for each LOB and presenting them to the RPC was targeted for June 30, 2012. This goal was not met, with some LOB risk identification occurring in the September through November timeframe. Electric Operations' identification process slipped to a later date. Company managers and executives have later recognized that the developing risk assessment processes in 2012 "did not take well," with the first step of the LOBs identifying their operational risks not being realized during the calendar year. The following chart shows the timing of research and development of the operating risk management program during 2011 and 2012.

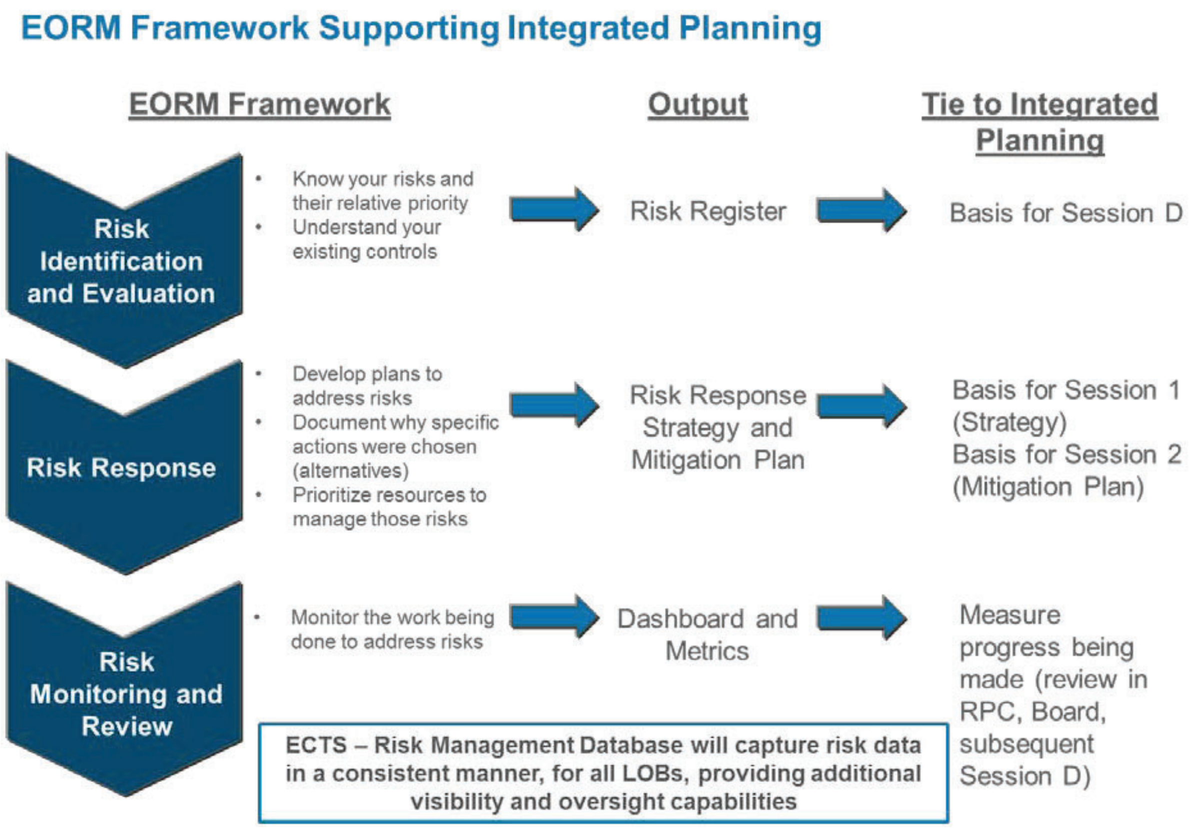
The Company then turned its focus to the Risk and Compliance (formerly called Session D) process scheduled to occur during the first quarter of 2013. The risk and compliance session is expected to identify and evaluate top LOB and enterprise risks and compliance issues that, if left unmitigated, could prevent the Company from achieving its strategic objectives. The output of this session is to inform the development of the S-1 strategy process for each LOB, and to drive the work and resource requirements of the S-2 process. The Company considers the early 2013 exercise within each LOB to be a preliminary and only partial test in the evolution of the risk assessment processes, which, if it develops as hoped will eventually drive the identification and assessment of risk mitigation measures, which will then flow into the corporate planning steps



that eventually produce projects, programs, and initiatives, which then will produce capital and O&M forecasts, which then will drive GRC filings. That result, we emphasize, is not what exists now, nor is likely to exist until the next GRC filing, if then. The next depiction provides an overview of the risk and compliance sessions.



This year's cycle is expected to establish a basis for learning how best to link risks and compliance requirements with strategic objectives and an action plan. The Company hopes that the 2014 planning process (for the horizon beginning with 2015) will allow the 2014 risk and compliance session to permit PG&E to "use risk and compliance information to allocate resources." The following chart shows the "end-state vision" that PG&E is planning to attain with regard to risk assessments that will be a driver of integrated planning and GRC forecast development.



4. Work Remaining to Reach a Mature State

PG&E has made substantial progress in developing corporate-wide risk assessment processes, but actual follow-through at the LOBs has lagged, as the next chapters of this report address. PG&E's integrated operating planning has introduced a new process that we consider to be leading-edge for the industry. Proceeding rigorously and aggressively with its development and

implementation should drive better consideration of LOB safety and security goals, and make them usable as a primary driver of planning/budgeting and eventually GRC development.

PG&E's new integrated planning process represents a significant upgrade over its previous processes and would place the Company at the industry's leading edge. Liberty believes that that PG&E's new planning processes are innovative and well-designed to provide for better linkage of strategy and goals to resource allocation and execution. The new planning processes should be effective and industry-leading when fully implemented. The integrated planning process includes risk assessments as a primary input that is designed to drive annual strategy, goals and resource allocation in the future.

Starting in 2013, the annual integrated planning process will include the leading risk and compliance session that will drive the development of S-1 strategies for each LOB. This specific feature of the new integrated planning makes its design suitable for incorporating risk assessments and considerations into strategies that drive resource allocation and execution plans.

The 2012 integrated planning process did not include LOB risk assessment processes that fed into the S-1 and S-2 planning, because the risk processes had not yet been developed early in the year. In 2013, the Session D has evolved into the Risk and Compliance Session that is being developed by the LOBs in the first quarter. This will be the first risk assessment and compliance action plans that will feed into subsequent S-1 and S-2 processes. PG&E recognizes that the 2013 integrated planning process is the "first time through" the entire process and that more developed risk assessments with more refined risk assessments and quantification will occur in future years.

III. Power Generation

A. Background

Energy Supply has responsibility for internally-owned generating facilities and contracts for power. This LOB's major segments consist of Nuclear Generation, which operates the Diablo Canyon plant, Energy Procurement, which executes and administers generation contracts with third parties, and Power Generation, which operates all of the non-nuclear, PG&E-owned generation. The scope established for our study excludes Nuclear and Energy Procurement is not applicable. The analysis of Energy Supply therefore focuses on the hydro, fossil and solar facilities. From a public safety perspective, the primary focus will be on the hydro units and associated property, although consideration of fossil and solar facilities has been included.

B. Power Generation's Risk Program

1. Relationship to Corporate-Level Risk Management

Unlike other utility facilities, where the objective is to keep people safe by keeping them out, utilities are required to maintain recreational facilities in connection with hydro projects. As a result, there is a wealth of experience in dealing with public safety issues, including how to maintain effective communications with the public and how to design and implement effective emergency plans. The addition of a risk-based approach, however, does present a new approach and set of methods.

Guidance from the corporate risk group has been more mechanical and procedural than operational. A large number of guides, policies, procedures, templates, forms, and other instructional-type material has been shared with the LOBs, and support from risk experts has been available. This level of support can be bolstered in three areas. First, we have already discussed the need for a definition of philosophy. The corporate group can work with management and stakeholders to arrive at a suitable approach.

Second, oversight functions have been lagging and it would be helpful for the program if they could be accelerated. In this context, we mean oversight of LOB implementation of the program, assurance that risk considerations are applied in accordance with program expectations,

assurance that appropriate risk scenarios are being examined, monitoring of preparation and implementation of risk response plans, and analysis and reporting on program status and effectiveness.

We recommend that corporate group accelerate its plans for providing effective oversight of LOB risk functions including risk considerations being applied in accordance with program expectations, appropriate risk scenarios are being examined, monitoring of preparation and implementation of risk response plans, and analysis and reporting on program status and effectiveness.

The defined governance provisions of the program are strong, but it is not clear that they are working as intended. It is difficult to see how the material formally emanating from Power Generation is sufficient to fully permit effective oversight by anyone. In addition, organizations like the RPC seem overextended such that there is limited time for safety issues. This seems to be confirmed by the published agendas. We recommend that ERM should evaluate the effectiveness of governance plans for the program versus the original intent and make recommendations to make the program more effective.

2. Power Generation's Risk Assessment Process

The tools and techniques of PG&E's program are noteworthy. In principle, they certainly rise to best practices. Some of the stronger program elements evidenced by Power Generation are:

- The existence of a structured approach to risk assessment with defined evaluation criteria and mechanics for scoring. Terms are well defined, scoring parameters are logically structured, and the instructions for rating various risks and consequences are consistent.
- An assessment tool based on the important principle of the product of likelihood and consequences is in place. Power Generation employs the RET, which measures likelihood and consequences. This brings an important tool to the table.
- The concept of inherent and residual risk is used. There are a number of benefits from using this technique, which is not as widely used elsewhere as some of Power Generation's other tools. This technique essentially provides a before and after scoring, which represents a clear measure of the degree and effectiveness of mitigation. Although

not used as such, it has potential for being especially valuable in cost-benefit analysis and in determining where one can get the most "bang for the buck."

- The level of effort devoted to assessments is generous. The way the program is structured, there is little opportunity for shortcuts or a less-than-detailed response. Power Generation has devoted the necessary resources and is making an effort consistent with a successful program.
- The conceptual approach to "alternative analysis" is good. The system provides the opportunity for a full ventilation of options and a good methodology for evaluation, although its implementation can be improved.

a. The RET and Operational Risk Priorities

The makings of a strong set of tools are already in place. Liberty believes that there is an opportunity for improvement in how Power Generation uses such tools. The RET, for example, contains the fundamentals critical to a risk program, but it is not clear that it is being used to its full potential. The tool is used by Energy Supply for the ranking of operational risks. Thus we can see in the Risk Register the operational risks identified by Energy Supply and the four which apply to Power Generation. Each risk is accompanied by its measure of risk from the RET tool, both on an inherent and residual basis. Residual risk is the measure after mitigation / controls are put in place.

It is not clear, however, what meaning those risk scores or rankings have going forward. They seem at this point not to be used again for any further purpose, including prioritization. One can ask whether their value was primarily in the construction of the Risk Register in the first place. The operational risks were filtered from a list of about 100 down to 21. It is understandable that the list of risks is regularly in a state of flux, both in terms of the nature of certain risks and the number of risks included. But we saw no evidence of this intent. Rather, it appears that the filtering process was more related to elimination of duplicates, combining risks, and eliminating choices perceived as weak. It does not appear that any RET or risk scores played a significant part in this process. The subsequent filtering down to nine exhibited some loose correlation to risk scores, but differed enough to show that other significant considerations were in play.

Our conclusion is that the risk rankings are not making the contribution one would expect, although, the process itself forces thinking and analysis that otherwise might not take place. That is a real benefit.

b. Risk Scores and Project/Task Priorities

The scores do not seem to be used to their full potential, but we do not necessarily see this as a major issue regarding the determination of operational risks. The real benefits of a ranking system come at the next level. Ranking and prioritization of a list of nine items is neither difficult nor useful. All nine are likely to be approved and scheduled to at least start in the near-term. Those nine may each spawn several projects or more, and each project will contain many tasks or sub-projects. The result can be hundreds of sub-projects or tasks, each contributing to mitigation of an important operational risk. The issue becomes how one determines from a risk and safety perspective what to do first when completing all the work might take years.

This question is important for PG&E. Hydro assets involve a large volume of risk-driven safety-related work. The large number of tasks that must of necessity be spread over several years makes the product of likelihood and consequences the most useful tool in selecting the work to be done first. A real value results in this environment where perhaps hundreds of tasks are planned to be done, as opposed to evaluation of a dozen operational risks.

This concept is not foreign to Power Generation and there is evidence of its use beyond the summary level operating risks. We did observe that the concept is in some use, but its effectiveness, uniformity of application, visibility to management, scope of use in the planning process, and application outside single projects is not clear. This appears to be a work in progress, and we recommend that the effort be formalized and plans for its future development and use laid out now. Power Generation and Energy Operations develop a consistent approach towards safety project/task prioritization using likelihood and consequences and applying priorities uniformly across all projects and tasks.

c. Relevance of Scores

We have expressed a positive view on the methods available to Power Generation, specifically the risk score calculation (likelihood times consequences) and its application on an inherent and

residual basis. Such data offer the opportunity to describe risks and mitigation on a quantified basis. We have also expressed the view that such powerful tools deserve better use.

In evaluating the Power Generation data, the various risk scores seem to lack substantial meaning. Consider that many of the risk scores for the nine operational risks fall into a logical range (180–354). Two, however, have scores of 9 and 49, leaving one to wonder how they relate to the others. In addition, the degree of mitigation, as measured by the percent reduction in risk scores, ranges from 4 percent to 94 percent, again leaving one with questions. An example is whether a top operational risk mitigated by only 4 percent, is satisfactory.

We thus have concerns with the scoring system. A valid approach will produce logical results. On a scale of 1,000, a score of 800 should be roughly, perhaps very roughly, twice as important as a score of 400. A score of 80 should be considered not too far different from a score of 40, with both being of minimal stature. If such relationships do not exist, then the value of the system must be questioned. The choice by management of very low scoring risks is ample testimony to the lack of confidence in the scoring approach.

The theoretical contribution of a valid scoring system is too great to ignore. The further opportunities for use of the mitigation percentages are extremely enticing, perhaps even offering hope of meaningful quantification of safety risks. Accordingly, it is recommended that Power Generation work on refining the risk rankings such that they facilitate more effective analysis and comparisons of risk and degrees of mitigation.

We recommend that Power Generation refine the risk score methods in order to facilitate more effective analysis of risks and degrees of mitigation.

d. Alternatives Analysis

In seeking mitigation options, Power Generation uses "alternatives analysis." Mitigation options are presented with an assessment of feasibility, implementation barriers, schedule for implementation, cost of implementation, and the degree of risk reduction expected. This decision-making tool is good, but it is not clear it is used for that purpose. Rather, the context in which we saw alternatives analysis was in reporting decisions apparently already made.

The Operational Risk Management Standard provides the following guidance:

> *The Risk Manager explores the range of mitigation possibilities, including an alternatives trade-off analysis and calculation of the relative costs and benefits of different options and documents the rationale for the recommended mitigation activities.*

We did not, however, observe any such analysis or rationale. Providing management with a range of mitigating options is critical. If that feature is missing, it presents an issue with the effectiveness of the technique. We recommend that Power Generation adopt the required approach to alternatives analysis to inform management of a full range of options, and not simply the one or two preferred by staff. In addition, the dismissed options should be preserved in subsequent reporting.

The treatment of alternatives brings to mind certain language by the IRP:

> *We saw no evidence of any in-depth strategic discussions about the alternates, level of investment, trade-offs, or other factors that would relate to mitigating the risk.*

Liberty has made several similar observations regarding strategic discussions, alternates, and level of investment, suggesting that limited progress has been made on this particular IRP conclusion. The perception exists, at least on the part of the IRP and Liberty, that issues and options are perhaps not being fully ventilated, and this of course raises questions about how funding levels have been determined and validated.

3. Assessment Results

PG&E's top-level risks, of which there have been nine, are Board-level, or enterprise, risks. One of these is hydro risk, and it is assigned to Power Generation. At the LOB level, there were about 100 potential items initially identified in the Energy Supply. That number was reduced to nine, four of which fall under the direct management responsibility of Power Generation.

a. Hydro Risk

The risk of a dam or other structural failure was identified as an enterprise risk in 2007. It does not appear that much was done as a result until such risks moved up in priority after the San Bruno incident. After that, there were at least three significant step escalations in the program, as well as a continuing growth in momentum. After the San Bruno incident in late 2010, Power Generation performed new baseline inspections for all canals and penstocks. After the issuance of the IRP report, safety-related asset management programs were substantially accelerated and funding expanded. In late 2011, the program was expanded once again.

The definition of the enterprise hydro risk has stayed the same:

> *Failure of a dam or other hydro facility resulting in significant damage to third parties, the environment, and/or the Company.*

The degree of time and effort applied to this risk in recent years is considerable. In addition to the many inspections and facility assessments, detailed risk considerations were applied and weaknesses or gaps identified. The relatively simple list of gaps that remains is misleading, because the analysis and work to get to that list were extensive. In structuring the hydro risk, Power Generation concluded it was essential to look beyond large dams to other hydro facilities. Accordingly, the scope is listed in three categories: (a) dams, (b) conveyances, and (c) penstocks.

i. Dams

The possibility of a large dam failure must be considered paramount in any consideration of hydro risk. Power Generation has examined this risk from the perspective of three risk drivers: dam failure due to large flood, large earthquake, and normal operations. Before proceeding with a discussion of risk, it is first important to understand the processes by which dam safety are managed and assured. In this regard, PG&E is double-regulated for the most significant dams:

- 171 PG&E dams
- 81 of which are under DSOD jurisdiction
- 54 of which are also under FERC's five-year Part 12D safety inspection

The underlying processes are extensive and large dams do not lack for attention. Power Generation makes extensive use of consultants and outside panels to review its facilities and processes. Regulators have been active in meeting their oversight responsibilities. In addition, safety criteria and regulatory oversight tend to grow with time. This factor brings an element of continuous improvement in terms of managing and lowering risks.

There is no question as to the effectiveness of dam safety management in Power Generation. The processes in place are extensive, and have grown more rigorous and testing with time. For our analysis, however, we considered how, if at all, approaches and activities have changed with the advent of Power Generation's risk management initiatives. We found that the risk program has substantially elevated the priority of Power Generation safety programs, along with added funding and resources. Overall dam safety has increased as a result; it is strong and growing stronger.

Power Generation's analysis relating to dams identified seven "gaps" for which mitigation measures have been identified and are in progress of being implemented:

- Large dams – failure due to flood
- Large dams – failure due to earthquake
- Large dams – failure due to normal operations
- Small dams
- Aging infrastructure
- Records management
- Knowledge management

ii. *<u>Conveyances</u>*

PG&E's 368 miles of conveyances include canals, ditches, flumes, siphons and low head pipes, tunnels, and natural waterways. All high and medium public risk canals have been inspected for structural and geohazard conditions and most (27 of 33) low public risk canals have also been inspected. FERC regulates those conveyances that are associated with a FERC-regulated project.

iii. Penstocks

PG&E's 86 penstocks stretch over 48 miles. All have been inspected and inspection packages finalized for about half. The assessments address wall thickness, venting, geohazards, and adequacy of penstock protection.

b. Operational Risks

The four top operational risks falling under Power Generation comprise:

- Fuel cell risk: Power Generation is responsible for two fuel cell facilities located at local colleges. With hydrogen and natural gas present in a populated public area, the risk of leaks and/or explosion is important to consider.
- Failure of conveyance risk: There is obvious overlap here with the hydro enterprise risk.
- Public access to conveyance risk: Given that PG&E cannot have full control over access to its facilities, there is a risk that persons can access the facilities and that could lead to injury.
- Ammonia release risk: The delivery, storage, and use of anhydrous ammonia could lead to injury or environmental issues.

4. Infrastructure and Safety

Aging infrastructure is a growing issue in the electric industry. It is well accepted that investment has been constrained in the past for a number of reasons, including over-capacity, pressure on rates, and the preparation for deregulation. PG&E's hydro investment may also have been limited for a time due to financial condition and when it appeared that the hydro facilities would be divested. The industry now employs many facilities beyond their planned lives and high replacement costs make it difficult and unlikely that an aggressive catch-up effort can be supported. We term this the "infrastructure sustainability risk," which we define as the risk that infrastructure deteriorates due to age and other factors at a pace and to an extent that makes future recovery prohibitively expensive.

However, whether this forms an appropriate area of inquiry for this study, which is restricted to safety-related risks is a pertinent question. We think so for three reasons:

- Many components of the hydro system are at an advanced age. This feature has real ramifications in terms of equipment's wearing and in light of the fact that standards under which old facilities were built are often inferior to current standards.
- It is reasonable to think that today's infrastructure problems will contribute to tomorrow's safety problems.
- Age is not a significant factor in Power Generation's assessments, and this could lead to future age-related issues. The belief that age alone should not disqualify an otherwise healthy facility or piece of equipment is common in the industry, and when taken in a one-by-one analysis it is indeed valid. However, when taken collectively, such that the overall age of the collective system grows too fast, the danger grows that the volume of eventual replacement demands is too great.

We see the infrastructure sustainability issue more as a business risk than a safety one, but it is suitably important in both categories. In any event, PG&E might be well served in adding infrastructure sustainability to its important risks. In addition, we suggest that Power Generation place greater weight on age when evaluating risk and replacement decisions such that the system as a whole does not age too quickly.

We recommend that PG&E consider adding a new enterprise-level risk on aging infrastructure. We also recommend that PG&E place greater weight on age when evaluating risk and replacement decisions such that the system as a whole does not age too quickly.

We recognize that one of the hydro risk gaps (Gap 5) is aging infrastructure; therefore, our concerns are partially addressed in Power Generation's approach. There are two features, however, which would make a more focused approach preferable:

- The infrastructure approach we recommend would require a strategy founded on a vision for future infrastructure, as opposed to a focus on fixing problems. Power Generation's entire program would benefit from that shift in focus.
- If business risks were included, a different strategy than that selected for Gap 5 might have been chosen.

C. Risk Response Strategy

1. Risk Response Plans

The last output of the risk program is a Risk Response Plan (RRP), which lays out the mitigation scheme. The RRP has flexible requirements, but must at least present:

- Risk response actions
- Schedule
- Funding needs and other resource requirements
- Reporting and monitoring requirements.

A large amount of effort and analysis precedes the RRPs, but no tangible benefits or program results can emerge until after the RRP is approved, and there is a time delay after that approval. One can argue that it is only with the issuance of the RRP that "points are put on the board."

The IRP was critical of much of PG&E's enterprise risk management process, but was most critical of implementation.

> *Simply put, 'the rubber did not meet the road' when it came to PG&E's implementation of the recommendations of its enterprise risk management process.*

It was clear that the IRP found the promise of more "program improvements" or "ERM recommendations" to be unfulfilling in the continuing absence of a stronger implementation program. An aggressive approach to RRPs, aimed at demonstrating program effectiveness from the start and putting at least some points on the board early in the game, would seem to have been a logical strategy. To the contrary, however, Energy Supply set a goal of only one RRP in 2012, and that was not met. At the present time, the one RRP goal is April 2013, with the balance of operational risks due by the end of the third quarter 2013. We believe that a more aggressive approach to RRP completion would be beneficial.

We recommend that Power Generation adopt a more aggressive schedule to the preparation of RRPs. RRPs should be broken into smaller packages if the size of the package is too big to expeditiously complete.

2. GRC Links

We expect the RRP to become the needed vehicle for directly linking mitigation of specific safety and security threats to the proposals in the GRC. The challenge, however, becomes more straightforward if Power Generation's own RRP policies are expeditiously implemented. A process whereby each RRP is directly integrated into Power Generation's work planning and management systems, and directly feeds one or more lines in the GRC, seems a reasonable and powerful approach to fulfilling the March 5th letter's expectations.

It is not necessarily too late to address the current GRC. Many of the safety or security projects proposed for 2014 and beyond do indeed flow from risk assessments and subsequent mitigation planning. These are discussed further below under "Level of Funding." In response to Liberty questions, Power Generation has packaged some of these projects by their linkage to the hydro risk, conveyance improvements, and other categories. We will explain the limitations of the current data later, but the data is nevertheless helpful in understanding relative spending and the potential for future improvements in the direct linkage of risk assessment and resulting safety projects.

3. Hydro RRP

In addition to creating the major risk in Power Generation, hydro risk is also the forerunner for implementation plans. This process has been far from straightforward. Important components of this enterprise risk have emerged over time and been implemented. This includes, especially, the necessary field inspections and facility analyses necessary to frame the issues in the first place, as well as specific physical work that became apparent.

The lack of a final, complete, approved RRP for the hydro risk is therefore not surprising. This evolution, however, illustrates the need for a better approach. Hydro risk capital projects proposed so far in the 2014-16 window already exceed $100 million. One should question what PG&E's management requirements are for a project of this magnitude. We suggest that the levels of commitment here require at a minimum a well-thought-out project design, a rigorous scoping and approval process, a detailed budget and schedule, and a project management scheme to track the execution of the project from cradle to grave. To the extent such structure is not

possible for whatever reason, the work can be divided into smaller packages, in order to assure the meeting of management objectives.

To call the presentation of the hydro risk confusing unfair, because there is a substantial amount of good work behind the projects. However, management and others charged with governance and oversight need a picture of the work that makes sense. In this regard, the inability to present a coherent story on the scope of the implementation work for the hydro risk, its eventual cost, its schedule, and what the hydro system looks like when it is done (*i.e.*, how the risk profile has changed), is a shortcoming at this point.

We recommend that Power Generation consider changing its approach to defining and structuring projects such that the work can be packaged in a manageable way, in order to give management a clear picture of the scope, cost, schedule, and intended results. Project managers will then have an important tool for managing work effectively.

4. Project Management

It took us some time to understand how the hydro risk project was being managed. We learned that a great deal was being done in virtually every aspect of project management; however, the visibility of the work beyond the implementing teams seems lacking. For example, we sought reports that would presumably have been required by executive management, or the RPC. The only document was a tabular listing of perhaps 130 detailed milestones planned for the project with an update of their current status. This listing may have some use to some managers, but it is not adequate to provide visibility for what is to be a more than $100 million project. There is no cost data, no overview of how the project is going, and no indication of deviations or items of interest to management.

On the other hand, many of the tools for effective project management seem to be in place at the working level. Detailed implementation plans, project work lists, budgets, detailed schedules, and action lists exist. There are weekly coordination meetings, a bi-weekly status review, a new system for tracking of open items, and internal cost reports.

We observed earlier (under "Power Generation's Risk Program") that oversight seemed to be a potential problem. With the reports currently available for upper management, this is likely to continue to be a concern. Recognizing that the hydro risk is the first and most important risk moving ahead with implementation plans, this need for more effective management reporting should be considered an important priority.

We recommend that Power Generation provide periodic reports that meet the standard of good project management, including credible analysis of cost, schedule, project issues, and other information needed for effective oversight.

D. Planning of Safety/Risk Projects

The process by which a company manages the identification, development, funding, approval, and subsequent implementation of projects is critical to the objectives of linking risks to tangible improvements. To the extent a robust system exists, it should not be difficult to overlay the requirement to track risk-driven safety projects from the cradle to grave. The PG&E system meets this criterion.

Power Generation employs a sound process for the planning of its work. Centered around the Project and Portfolio Management (PPM) module of SAP, the procedure provides for an orderly flow of new projects through three phases. Projects enter the system from many sources under the principle that "everybody is a planner." In the first phase, project classification, a triage process is employed to filter emergency work and other clarifying characteristics. Non-routine projects then move into a project definition phase while others move directly to Phase 3 for project evaluation and concurrence.

PPM is a highly mechanical system with an elaborate scoring process. Nevertheless, Power Generation notes that decision-making is far from mechanistic, with team reviews responsible for final project priorities and decisions. The detailed list of projects included in the GRC work papers are direct outputs from PPM. The tool is extensive and flexible such that it should easily be able to adapt to the new challenge of linking risks to projects and maintaining that identity throughout the life of a project.

The scoring system employs seven attributes as listed on the accompanying table. The final score is the product of these parameters. Multiplying so many numbers together can produce a huge range of values and Power Generation uses a normalizing divisor (10,000) to place the final score in a more manageable range. This does not change the fact that the eventual span of the final scores is nonetheless dramatic – orders of magnitude.

Attribute	Range of Values
Justification	20 for base 0 - 10 for other
Asset criticality	0 - 17
Vulnerability	0 - 10
Health	1 - 10
Prioity	0.2 - 10
Urgency	0.2 - 10
Other	1 - 10

A key observation here is that this score defines the priority of a project, but it is divorced from the prioritization schemes of the risk process. Although Power Generation emphasizes that "safety work always gets done," it is not clear by what mechanism this occurs, or even how safety is defined in this context. In addition, we have assumed that the safety tasks will number in the hundreds; hence it is a question of when and in what order safety works gets done, more so than if the work gets done.

We observed earlier that the RET risk score seemed to die at that point. It would seem appropriate that the risk rating stay with a project for life and that it somehow be factored into, or perhaps in some cases even dominate, the PPM score.

Liberty also believes that some adjustment in the scoring formula should be considered in order to provide more meaning to the scores and their relative positioning. It is difficult to understand the relative importance of projects with scores around 1,000 compared to many projects with scores less than 1. Intuitively one would expect that such relatively low scores would mean the projects would be dropped from consideration. However, that is not what the Power Generation process appears to do. We therefore have here the same issue faced in the RET scoring; *i.e.*, how to give meaning to the scores.

In this case, the solution may be easier than the RET challenge. For example, using a sum of the attributes, perhaps with weighting if desired, rather than a product will reduce the range to a reasonable number. If the product is deemed important, then a square or other root of the score

will have the same effect of creating a manageable range and relationships. We recommend that Power Generation revise the PPM scoring method such that the resulting scores are over a manageable range and the relative values of the scores have some reasonable physical meaning.

In summary, PPM is sure to be the key tool in making a meaningful linkage between risk assessments and physical improvements. Projects can be fed from RRPs into PPM and managed cradle-to-grave. The modifications to the planning process and to the PPM tool to accommodate the risk/GRC linkage should be minimal and hence are recommended. We recommend that Power Generation modify PPM to facilitate the linkage of risks to projects.

E. Other Power Generation Safety and Security Initiatives

1. Public Safety

Public safety, although obviously important in utilities and other businesses, has not had the stature or level of attention of other programs, including employee safety. This was an observation of the IRP. PG&E's response has not been particularly aggressive, with a manager being appointed for public safety programs only in late 2012. Nevertheless, public safety is taking its appropriate place in the hierarchy of priorities. However, this is not new for Power Generation, where public safety issues have long been an important part of its programs. Power Generation facilities are in many cases open to the public, and include recreation areas specifically designed for the public. Other Power Generation facilities range over extended areas with many neighbors and physical limitations that limit Power Generation's control of access.

Power Generation presently has a Public Safety Officer and is adding two additional people to her staff. A new comprehensive public safety program has been created and is detailed in the GRC filing. Key features include:

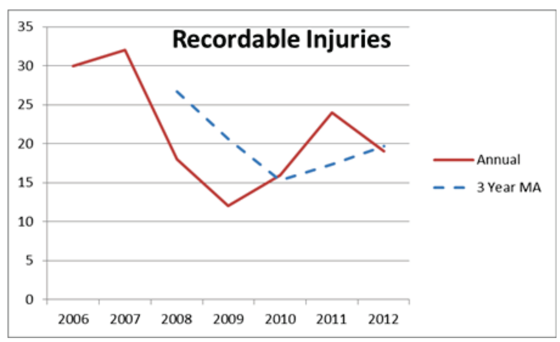
- Expanded efforts at public education
- Added warning and hazard signage
- Expanded initiatives in emergency preparedness
- Improvements to assure safer access to facilities and lands.

Large dollar initiatives do not necessarily flow from sophisticated analyses of risks. In some ways they are nevertheless as or more important than the major risk-driven physical improvements. We anticipate that their payback, (*e.g.*, in terms of public injuries or fatalities, is likely to be higher than the more massive investments. Accordingly, there needs to be a place in the risk/safety equation as well as visibility and priority for such initiatives. Given the low dollar requirements, there can be a tendency for such important work to get lost in the bigger picture.

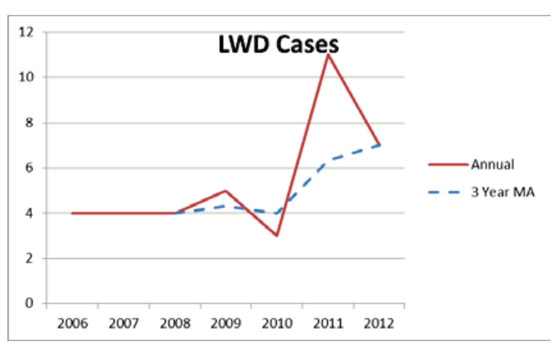
A major challenge in the public safety area of Power Generation is the lack of metrics. Public safety metrics and benchmarks are not in widespread use, and many of the hazards posed by Power Generation's facilities are unusual. Nevertheless, Power Generation sees this as an important challenge and is continuing to work on development of such metrics.

2. Employee Safety

From a Power Generation perspective, we have no reason to question management's commitment. Safety statistics, as they do throughout the Company, beg the question of just how much Power Generation has improved, and what is likely to evolve in the future as the Company continues its "safest utility" quest. We do note that this is a particularly aggressive goal given PG&E's recent performance.



Consider the trend in Power Generation recordable injuries, as shown on the adjacent chart. After a substantial improvement of nearly a factor of 3 between 2006 and 2009, the trend is again moving upwards in 2009 through 2012. This is highly unusual and, we suspect, well out of line with what one might expect. The data would have us believe that the heavy emphasis on safety in the last few years had no effect.



The results in terms of serious incidents add even more questions, because the pattern has been quite

different. Consider the trend in lost work day incidents, which was level during the years that less serious incidents declined by nearly a factor of three. Results have deteriorated significantly. We caution that in the case of serious incidents, we are dealing with small numbers. Year-to-year fluctuations can therefore be suspect. We think this data is representative, however, since it is generally consistent with the far more numerous statistics at the corporate level.

There is some concern that PG&E's previously punitive approach to accidents may have artificially depressed the recordable injury statistics, because of individuals being hesitant to report accidents. Of course serious incidents cannot be hidden; therefore, that could explain the opposite trends in the data. If this is true, Power Generation's actual performance in past years can only be judged by the LWD data. In addition, future improvement trends in less serious incidents will be difficult to discern because we will be measuring against a flawed base.

3. Security

There is a significant enterprise risk (terrorism) related to security, but that is managed under Corporate Security and Power Generation's role is limited. In addition, the local security risks in Power Generation are also supported by Corporate Security. Security as a utility issue has grown in importance in recent years. NERC requirements for Critical Infrastructure Protection (CIP) continue to grow. Cyber security is a major focus now, although it is excluded from the scope of our study. Power Generation's facilities are affected on a limited basis by CIP requirements. A small number of facilities are deemed critical and these qualify because of their switching or black start capabilities. Related projects are included in the GRC. At the present time, there are no significant security issues as they relate to Power Generation.

4. Emergency Management

The science of emergency planning and management has grown considerably in utilities over the last decade. There has been a wide range of interests, from storm restoration to business continuity. Accordingly, most utilities have added skills and capabilities in this area and are growing increasingly sophisticated. For Power Generation, emergency planning has long been a required component of dam safety. FERC requires emergency action plans (EAPs) for all high hazard dams. Power Generation is responsible for 54 of them. The term "high hazard" refers to the potential consequences of a failure, not the possibility.

Power Generation's emergency management approach is structured around the National Incident Management System (NIMS). This approach uses an Incident Command System (ICS) in establishing an emergency response organization. Power Generation people are trained and drilled in this approach and are well-versed in its requirements.

Power Generation's hydro approach relies heavily on local emergency management agencies (EMAs). Power Generation maintains close coordination with these responders, including monthly communications, periodic open house, annual orientations, and periodic drills. A "typical" emergency would be managed by a Power Generation incident commander and the EMAs. Escalated emergencies, which are less likely because of the regional nature of the facilities, could be managed by the state emergency function and could also include escalation to Power Generation's corporate level emergency response plan.

Power Generation has extensive experience and capabilities in emergency management and no issues are apparent.

F. Level of Funding

From a GRC perspective, all of our discussions funnel eventually to the question of "how much." In our case, the question relates to safety and security proposals included in the filing. Our assignment is, in part, to determine the cost-effectiveness of GRC proposed safety and security projects, and there is a wealth of data on that topic, which will be addressed later under "Technical Evaluation." The more interesting question for stakeholders is how those various proposals add up to impact the ratepayer, so the questions of how that eventual level of spending for safety was determined and its appropriateness are paramount.

1. Drawing the Spending Line

The total planned Power Generation spending provided for in the GRC for 2014 is:

Capital

Approximate number of projects	725
2014 spending	$345 million

Expense

Approximate number of tasks	800
2014 spending	$191 million

Both the capital and expense spending levels are more than 30 percent higher than the corresponding 2012 levels. As we discuss below, it is not possible at present to define precisely which portion of the spending goes to safety and security projects because of the lack of a satisfactory definition. The data do show that a disproportionate share of the increase can be ascribed to projects categorized as safety under whatever definition is finally chosen.

The GRC includes volumes of details on individual projects. In fact, the Power Generation data as noted above has more than 1,500 line items and accompanying details. At the other end of the spectrum, the GRC includes general descriptions of the programs that drive the individual projects. So we have high level conceptual commitments on the one hand, and thousands of pages of supporting details on the other. Neither is particularly helpful or appropriate for the evaluation of the aggregate spending levels.

A major element of our study was to examine how PG&E links risk analysis and mitigation to the level of funding sought for safety and security in a GRC. If that initiative is to prove successful, all parts of the process must culminate in a credible end result. That bottom line result must be supported by a clear rationale, to permit stakeholders to fully understand it, regardless of their ultimate level of support for it. This is especially critical when the bottom line represents a major departure from past practices, as does the safety and security spending in this GRC.

Any linkage between risk and safety-related spending strikes us as irrelevant if one cannot understand the resulting rationale for the level of spending. An infinite number of projects can be conceived; most organizations do indeed generate a lengthy wish list. Management therefore needs the ability to "draw the line" at some appropriate level; *i.e.*, to determine what aggregate level of spending makes the most sense, and to decide which proposals to delete or defer.

Power Generation management, and their PG&E managers, did indeed go through such a process, and did draw the line; specifically at $345 million and $191 million for capital and expense respectively in 2014. Projects with a lower score than those aggregating to these totals

were deferred to 2015 and beyond. Liberty was unable to determine how that process was conducted or, more importantly, what the rationale for the final choices was once the process was completed. The closest we were able to obtain to a rationale was the following, in response to the direct question of how the cutoff levels were established in the GRC:

> *The targets were proposed based on an assessment of the risks of rescheduling work to future years vs. the ability of Power Generation and its contractors to successfully execute the work. The forecasts presented in the GRC represent a ramp-up of expenditures over the 2014-16 period. This is the level of investment that PG&E believes is necessary to continue to provide safe, reliable, and affordable energy while meeting all federal, state, and local regulatory requirements, and public safety, recreation and environmental commitments.*

Such an explanation does not present a convincing rationale and justification for a spending level substantially beyond previous levels. It raises the question of how the regulator and other stakeholders can judge the appropriateness of the chosen spending plan. It begs the same question for management. We believe that management and the board of directors relied on a better explanation in approving the 2014 plans.

Our attempts to understand the aggregated spending level, encountered three major barriers:

- Lack of a suitable analysis, rational, and justification
- Lack of a workable definition of safety and security
- Lack of confidence in the 2014 work lists.

These impediments are discussed in more detail below.

a. Lack of a Suitable Analysis, Rational, and Justification

We questioned what should be required to justify increasing the investment in safety and security by a substantial amount, by a factor of 2 or 3 in some cases. We used the following check list:

- A compelling policy that drives the need
- A long term vision of what the future infrastructure looks like
- A long term plan to achieve that vision
- An analysis of associated rates to assure sustainability

- Defined near term projects that are justified in the context of the long term plan (and not just on their own merits)
- Analysis / justification of the bottom line
  - Why that number is optimum
  - The benefits that will result
  - The benefits or consequences of more or less spending.

With the exception of the first item, the policy definition, the other features are not present. We have alerted Power Generation to this gap, which we consider significant.

b. Producing a Workable Definition of Safety and Security

In seeking to parse the safety and security data in a workable format, we considered a number of definitions, none of which we found particularly satisfying or especially helpful. The chart below illustrates the wide disparity among four specific options.

Various Definitions of Safety and Security Projects

	All GRC Line Items	Safety and Security Line Items	ERM Hydro Risk Line Items	MWC 2L Safety and Regulatory	"Safety - Other" Line Items
Approximate number of capital projects	725	425	180	41	23
Forecast 2014 capital expenditures	344,644	133,337	126,363	49,614	18,893
Approximate number of expense tasks	800	150	65		17
Forecast 2014 expense	191,144	40,996	31,322		6,650

It is clear that we cannot have a rational discussion of the degree of safety and security efforts without a mutually agreeable definition. In the case of our four options above, the definitions are as follows:

- Safety and Security: This was a judgment by Power Generation after reviewing all of the GRC projects and deciding which had some relationship to, or impact on, safety.
- ERM Hydro Risk: Under this definition, only safety and security projects related directly to the hydro enterprise risk were considered.
- MWC 2L: The major work category of "Safety and Regulatory."

- Safety – Other: Liberty extracted the projects in PPM for which the justification was given as "Safety – Other."

We will use some of these definitions in our discussion but do not believe any are sufficient for the long-term. For the CPUC direction to be implemented effectively, and for a positive dialog on safety and security to be conducted, we need a better definition, one whose criteria might include:

- Facilitates linkage of spending to risks and mitigation
- Allows measurement of the commitment to safety and security and the trend of that commitment
- Provides a clear picture to stakeholders of where and why the money is needed.

With this in mind, we recommend that, for purposes of evaluating spending on mitigation of safety and security risks, only projects with the following attributes will be considered:

- The project is listed specifically in a Risk Response Plan associated with an enterprise, RPC-level, or operational risk
- The mitigation sought is for risks associated with (a) public safety, (b) employee safety, or (c) security matters that could jeopardize public or employee safety
- Where multiple mitigation objectives exist, the project qualifies only if it would have been done anyhow had safety or security been the only mitigation objective.

It sets a reasonable standard for the future and will allow a strong foundation from which the CPUC proposed program can grow.

As a high priority, we recommend that Power Generation provide an improved analysis and rationale for the proposed spending levels. Typical information that should be provided includes:

- A compelling policy that drives the need
- A long term vision of what the future infrastructure looks like
- A long term plan to achieve that vision
- An analysis of associated rates to assure sustainability
- Defined near term projects that are justified in the context of the long term plan (and not just on their own merits)

- Analysis / justification of the bottom line
  - Why that number is optimum
  - The benefits that will result
  - The benefits or consequences of more or less spending.

c. Lack of Confidence in the 2014 Work Lists

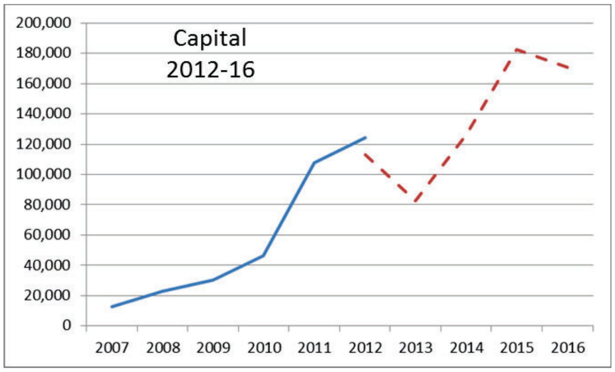
The planning and budgeting for any company, particularly in later years, carries a degree of uncertainty. The combination of the GRC process (which approves total spending levels, rather than specific projects) and Power Generation's internal workings makes it very unlikely that the projects that actually get done in 2014 will match the GRC list very closely. This is a problem, in that we really do not know what projects are being approved for 2014. We are left with a funding level whose rationale is not clear and a list of projects that is invalid. The uncertainty in the project list flows from several factors:

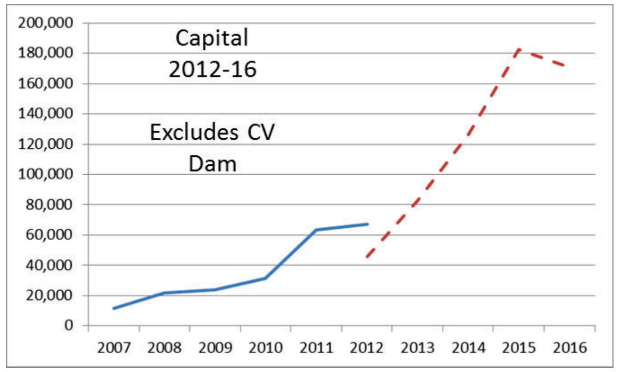
- It is predicated on the amount requested by Power Generation, which is not likely to be granted in full.
- It does not account for carryover work from prior years, which inevitable will displace some of the projects now proposed for 2014.
- It does not account for new work, which is sure to materialize before 2014, especially as the generation of RRPs picks up.

It would seem prudent to modify the planning process in the future to: (a) provide allowances for new and carryover work, and (b) provide the list of projects that are proposed to be deferred if less than requested funding is granted by the CPUC. Such an approach will go a long way towards creating a much-improved understanding of the work that can be accomplished. It will also provide a more realistic base from which to monitor performance against plans.

2. Spending Trends and Allocations

In analyzing trends, we used the most liberal definition of safety and security projects which, as a reminder, is Power Generation's judgment after reviewing all of the GRC projects and deciding which had some relationship to, or impact on, safety.

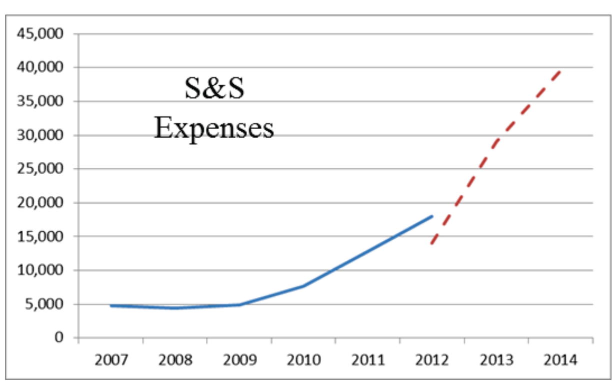




Power Generation has recently completed a major seismic upgrade project at the Crane Valley Dam and that significantly distorts the trend curves. Accordingly, we have presented curves with and without Crane Valley. Note that spending proposed for 2014 and after is sharply higher. In the case where CV is excluded, spending approximately triples. This is the basis for our earlier remark about safety spending increasing by a factor of two or three.

The major (>$5 million) 2014 projects are:

- Drum Canal/Gunite Work
- Bear River Canal Gunite
- Penstock Program (Asset Management)
- Fordyce Dam Leakage Reduction
- Wishon Dam Repl Slabs/Joints
- Dam Remediation (Asset Management)
- Potter Valley Repl Low Wood/Metal Penstock
- Dam Safety Instrumentation Automation (Asset Management)
- Water Conveyance (Asset Management)
- NERC-Required Security

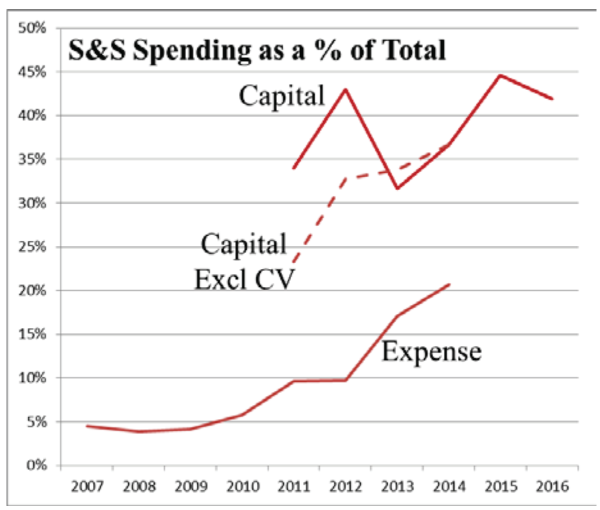


The trend in expense work is also significant, although not to the extremes of capital. Nevertheless, the 120% increase in only two

years (2012-24) is substantial by any measure. Note the relatively low amount of pre-San Bruno spending. The major (>$1 million) line items in the expense plan are:

- ERM activities
- Records management initiative
- Water conveyance assessments program
- Penstock program
- Dam safety instrumentation
- Dam repair program
- Facility safety programs
- Shasta required facility safety program
- Kerckhoff dam repair LL outlet valve #3
- Pit 5 OC low level outlet abandonment

It is useful to examine the portion of the capital and expense budgets devoted to safety and security over time. Safety and security is taking a sharply higher share of the budgets, although capital is somewhat constant if CV is included.



Although we obviously face analytical challenges as a result of definitional problems, the message of growth in safety and security is nonetheless very clear. In addition, we might expect to see a significant further escalation as the risk assessment process matures and more RRPs are issued, generating more projects. We are therefore unable to judge the appropriateness of that final level of spending, but we can indeed conclude that Power Generation is aggressively attacking safety issues in its infrastructure. Unfortunately, the magnitude of the increases makes the lack of better justification of the bottom line an even more serious omission.

G. Technical Evaluation

Our study included an evaluation of the proposed projects with the intent of commenting on their quality and cost effectiveness as justified by PG&E. The number of relevant GRC line items is about 575; therefore, a project-by-project analysis is not practicable. It is therefore more appropriate to conduct the technical analysis by testing attributes that characterize the overall process as well as other elements thought to influence the technical quality of Power Generation's work. These include:

- The quality of the engineering and decision-making processes
- The skills and capabilities of the people and organizations
- The effectiveness of oversight and management direction
- Analysis by major category, the nature of the projects, how they flow from risk assessments, and meet safety and security objectives, and trends in spending in these categories.

1. Project Processes

We have discussed the processes by which risks are assessed and projects defined. The risk process is very well advanced, although it is still fair to characterize it as a work in progress, particularly as applicable to the direct linkage of risks and projects. With respect to work planning, Power Generation has a strong system centered around PPM. And finally, the engineering analyses that have driven infrastructure examinations and improvement proposals, particularly in Asset Management, are impressive.

Accordingly, we would conclude that, to the extent that the technical adequacy of Power Generation's proposed safety measures are a function of engineering, risk, and decision-making processes, such measures are likely to be on balance cost-effective and of high quality.

2. Skills and Capabilities

While there are many Power Generation organizations upon which the success of these programs relies, the technical excellence question will be dominated by Dam Safety and Asset Management. The dam safety organization is led by a Chief and four direct reports, all of whom are experienced professional engineers. The group is expanding with a deputy and three

additional engineers. The group is active and seems well-regarded in the industry. They are particularly active in benchmarking and lessons learned. Dam safety requires a significant use of consultants both for production work and oversight by consulting panels.

The Asset Management organization was formed in 2010 and has been the leading function in identifying Power Generation's infrastructure risks and developing programs in response. The level of production and the quality of the group's output in the last few years appears to be extraordinary. It is difficult to imagine what the state of the risk program would be today without the products of this organization.

The group consists of a manager, two lead engineers, three analysts, and 12 contract engineers. We have concern about the long-term presence of contractors. It would seem that after three years, the group should have started to wean itself from such a large consulting staff, and begin the transition to greater internal capabilities. The IRP noted PG&E's need to rebuild the core of technical expertise. Extended reliance on outsiders in what has become one of the most important and effective core business functions is not the way to "rebuild technical expertise." We have discussed this issue with Power Generation management and there seems to be a consensus that the transition to a primarily internal set of skills and capabilities is overdue. Management is likely already starting down this path.

In terms of supporting organizations, we were exposed to a broad cross section of Energy Supply personnel over a period of several months. Their level of participation in this process allowed us insights that would otherwise not be possible. During all of these interchanges, we never saw any reason to question the skills and capabilities of the Power Generation people and organizations.

In summary, we would conclude that, to the extent that the technical adequacy of Power Generation's proposed safety measures are a function of the technical and support organizations and the skills and capabilities of the people, such measures are likely to be on balance cost-effective and of high quality.

3. Management and Oversight

We begin by noting the high degree of regulatory oversight applied to the Power Generation organization. Such an environment as has existed for a long time establishes a strong sense of the need for compliance. With the number of people looking over Power Generation's shoulder, we are confident that suitable external oversight is present and reasonably effective. FERC oversight includes new risk-based decision-making initiatives including the potential for ALARP concepts, a five year mandated review of all high hazard dams, and FERC mandated emergency plans. At the state level, California, via DSOD, is thought to be the most thorough state in the regulation of dam safety. Finally, with the escalated oversight of the CPUC in safety projects, as will be recommended later in this report, the effectiveness of regulation is likely to increase even further.

Regarding internal management and oversight, we earlier expressed concerns about the risk program. Oversight efforts seem to be lagging, and the RPC seems overextended and tasked with too much. The apparent inadequacy of the quality of reporting to management is a consistent theme; it is difficult to fulfill one's oversight responsibility in the absence of information.

We saw no evidence that this issue should influence risk assessments and evaluations of projects. We conclude that, to the extent that the technical adequacy of Power Generation's proposed safety measures are a function of regulatory and management oversight, such measures are likely to be on balance cost-effective and of high quality.

4. Project Categories

In this analysis, we will again use the GRC subset defined by Power Generation as "safety and security" (S&S).

a. Type of Facility or Work - Capital

Growth in Annual Spending		
	2012	2014-16 Average
Hydro Dams	12,011	49,102
Canals	12,109	43,198
Penstocks	712	41,119
Flumes	3,597	11,310
Tunnels	1,019	4,087
	29,449	148,816

Dams, canals and penstocks represent the bulk of the proposed 2014 spending with 76 percent of the 2014 work. This grows to 82 percent by 2016. Major spending on flumes and tunnels does not occur until 2015, but then adds $42 million in 2015-16. These projects, which flow from a variety of sources including the ERM program, represent a massive escalation of effort from past spending levels. Consider the adjacent table which illustrates that average annual spending levels are increasing by a factor of 5 over 2012 spending. This aptly demonstrates the degree of "catch-up" spending that Power Generation feels is required for these facilities.

Safety and Security Capital Projects		
	2014 ($1,000)	% of Total
Hydro Dams	38,710	29.0%
Canals	38,545	28.9%
Penstocks	24,070	18.1%
Powerhouse equipment & facilities	5,979	4.5%
Security	5,100	3.8%
Other waterways	4,200	3.1%
Public Safety	4,125	3.1%
Arc Flash Mitigation	3,189	2.4%
Flumes	3,026	2.3%
Dam Gates	2,535	1.9%
Roads, Bridges, walkways	1,888	1.4%
Tunnels	762	0.6%
Ergonomic projects	683	0.5%
Electrical Safety	250	0.2%
Reservoir Log Booms	175	0.1%
Dam Low Level Outlet	50	0.0%
Fall Protection	50	0.0%
Total	133,337	100.0%

While all other categories are dwarfed compared to dams and the conveyances, many are still important and of interest, with the full list for 2014 shown in the accompanying table.

- There are multi-million dollar security initiatives in 2013-14 but very little otherwise.
- The public safety category increases significantly for 2014 and then doubles again to $8.8 million in 2016.
- Spending for arc flash mitigation continues at a level of several million dollars per year after spending of three times that much in 2012.

- Capital for electrical safety drops to token levels after multi-million dollar spending for many years. This seems to be more than offset by increased spending for facility safety that is charged to expense.

b. Project Initiation - Capital

The capital projects that comprise the GRC originate from six basic sources, with the bulk of the work falling into only three. These are broken down in the uppermost table on the below illustration.

The major category is dam and facility safety initiated projects, which are planned for $209 million over the five-year period. The second major category captures the projects initiated through the various Asset Management studies and programs. They amount to $200 million in the five year period.

All S&S Projects

Capital	2012-16 Total	% of S&S Funding
Dam Safety / Facility Safety Program Initiated Projects	208,553	31%
Asset Management Initiated Projects	199,759	30%
ERM Initiated Projects	173,162	26%
Related Specific Dam, Water Conv. and Pens. Projects	63,570	9%
Public Safety	20,227	3%
NERC Security	9,950	1%

ERM Initiated Projects

	2012	2013	2014	2015	2016	Total
Drum Canal/Gunite Work (Cap)	2,000	1,800	13,500	13,500	13,500	44,300
AM: Penstock Program CAP	0	50	8,000	18,000	38,000	64,050
Bear River Canal Gunite	3,996	3,000	5,000	5,000	6,000	22,996
Drum - South Canal Shotcrete	2,000	2,000	3,500	3,500	3,500	14,500
Drum - Wise Canal Shotcrete	2,000	500	3,500	3,500	3,500	13,000
Bear River Canal - Berm Stabilization	200	750	750	750	750	3,200
South Yuba Canal Gunite	500	500	500	500	500	2,500
Towle Canal Shotcrete	387	400	400	600	600	2,387
TigerCr Canal-Instl PillasterJointsLiner	310	681	323	330	0	1,644
Lime Saddle Patch U. Miocene Canal	0	0	250	0	250	500
Camp 2 Flume Replace Liner	150	550	0	0	0	700
Bear River Canal Repair	300	0	0	0	0	300
Phoenix Flume Sheet Liner	275	300	0	0	0	575
Coleman Gunite Canal	0	0	0	160	0	160
South Yuba Box Flume Replacement	0	0	0	450	1,900	2,350
Total	**12,118**	**10,531**	**35,723**	**46,290**	**68,500**	**173,162**

92%

The third category is of particular interest to us since it flows from ERM initiated projects. These items amount to 26 percent of all safety and security funding, or $173 million. Ideally, if the wishes of the CPUC can be achieved, virtually all major S&S expenditures should flow from the risk program. Of course with the narrower definition of safety and security we propose, the total list of projects is likely to be less as well.

The ERM projects are listed in the lower table above. The projects are sorted by 2014 spending. Note that the list is dominated by the top five projects which amount to 92 percent of the requested funding. Four of those top five projects are canal projects, as are most of the projects on the list. All of these projects are associated with only one of the seven gaps defined in the hydro implementation plan, and that is Gap 5 – aging infrastructure.

There are a number of important risk program messages embedded in this data. It illustrates that the direct physical work flowing from the risk program is limited at this point. This is not a surprise as we have already noted the limited progress of RRPs. Also, while the dollar volume of projects is considerable, the number of projects is limited – only five can be considered sizable efforts. Finally, the fraction of safety and security projects whose genesis lies in the risk program is small, and this is a function of a small numerator (limited ERM projects) and large denominator (inflated definition of safety and security projects).

The data starts to paint a picture of what future GRCs could look like, with a rigorous definition of safety and security initiatives and a strong linkage between those initiatives and the system risk assessment.

c. Project Justification

PPM includes a designation of the primary justification category for each project. It will be desirable to include eventually a field for linkage to an RRP and the designation as a safety or security project by whatever mutually agreeable definition is approved. In the meantime, the justification contained in PPM provides a good understanding of what has motivated most projects. The accompanying table shows that the vast majority of

Justification	Number of Projects	2012-16 Funding
Reliability	79	432,269
Safety - Mandated	6	126,305
Safety - Other	30	54,367
Regulatory Required - Mandated	6	13,501
Infrastructure	1	95

projects are justified on the basis of reliability. The definition used by Power Generation allows such reliability-driven projects to be categorized as safety-related if there appears to be a contribution to employee or public safety.

d. Type of Work - Expense

The largest expense category is facility safety, with a substantial proposed spending increase over current levels. Dam and conveyance work approaches half of the spending on safety and security and this is nearly all new money, having only token amounts in these accounts in 2012. The public safety line is also noteworthy. Again, funding was minimal in 2012 but has changed by factor of 10 in 2014.

Safety and Security Expense Items

	2014 ($1,000)	% of Total	Change 2012-14
Facility Safety Program	8,700	21.2%	2,493
Hydro Dams	7,616	18.6%	6,723
Dam Low Level Outlet	4,725	11.5%	4,286
Penstocks	3,665	8.9%	-177
Public Safety	3,594	8.8%	3,212
Documentation and Data Accessibility	2,612	6.4%	2,612
Training and Qualifications	2,554	6.2%	219
Other waterways	2,109	5.1%	681
Security	2,064	5.0%	2,064
Dam Gates	717	1.7%	708
Powerhouse equipment & facilities	674	1.6%	653
Fall Protection	640	1.6%	392
Ground Grids	548	1.3%	282
Roads, Bridges, walkways	398	1.0%	391
Arch Flash Mitigation	210	0.5%	95
Tunnels	90	0.2%	92
Miscellaneous Safety	80	0.2%	-87
Total	40,996	100.0%	24,640

Documentation and data accessibility, a fallout from the ERM hydro risk, represents a major new program in the multi-million dollar category.

Security costs, which were previously zero in the expense budget, now consume more than $2 million.

e. Non-Hydro Projects

We have not discussed in detail to the balance of the Power Generation fleet, which consists of three fossil units and a number of solar and fuel cell projects. This does not mean, of course, that these other units are ignored in the risk assessment process. To the contrary, two of the four operational risks discussed above are in non-hydro facilities (ammonia at a fossil plant and hydrogen and gas risks at the fuel cells). But the risk levels and appropriate spending levels for the non-hydro facilities are considerably less, probably by two orders of magnitude. Power Generation is applying a focus on these facilities that can be considered substantial and adequate.

f. Summary of Safety Projects

A key objective of this GRC was to create a new priority for safety and security. That objective has surely been met. We have seen that proposed spending in 2014 and beyond has expanded by more than 30 percent over 2012 levels, but that does not tell the story. When spending increases are confined to safety categories, the increases are greater, by a factor of 2 or 3 or more in some cases. The definition of safety and security, which overstates the number of projects classified as safety, at the same time causes an understatement of the magnitude of the percent increase.

Therefore, it is clear that Power Generation has elevated the consideration of safety, and seeks corresponding funding. There is an element of catch-up, particularly as applied to infrastructure. Spending in recent years has been relatively small and, prior to that, spending was constrained by first the financial condition of PG&E and then the belief that hydro facilities would be divested. Critics might characterize this as neglect of the facilities, but our experience suggests otherwise. These were real limitations for utilities caused by changing circumstances at individual utilities and the industry in general. Catch-up at this time is indeed an appropriate and prudent strategy.

Our evaluation concludes that: (a) the elevation of priorities in Power Generation has been appropriate and successful, (b) the nature of the projects is consistent with the needs of the system and the new priorities, (c) the technical development of projects is strong and they are suitably justified and of adequate quality, and (d) while linkage to risk assessments remains limited, a picture of how this can and should work in the future has emerged and the vision seems to be absolutely attainable. The one major question hanging over all of this is the aggregate level of spending, whose rationale and justification remain clouded.

IV. Electricity Distribution

A. Background

PG&E's Electric Operations LOB operates one of the largest single-company, single-state electric distribution system in the United States. The PG&E service area covers 70,000 square miles, and ranges from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada mountain range in the east. PG&E operates and maintains the following electric distribution facilities to serve approximately 5.1 million electric customer accounts:

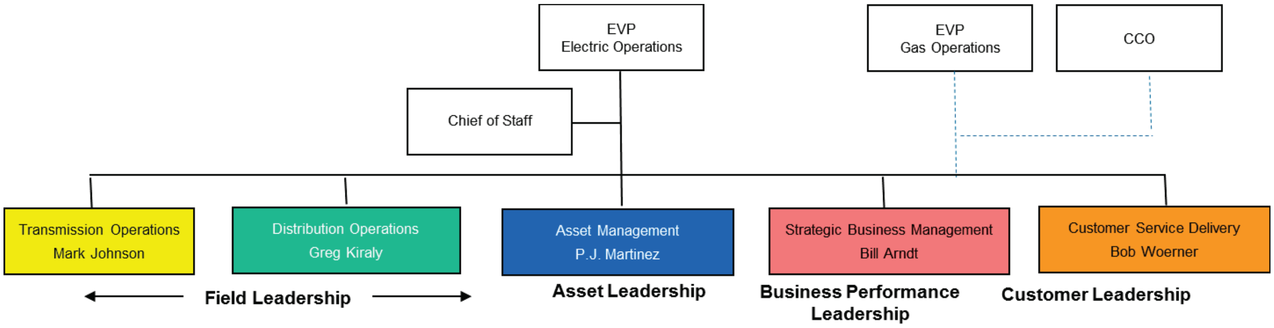
- 113,500 miles of overhead primary distribution circuit
- 2.4 million wood poles
- 27,000 miles of underground distribution circuit
- 8,000 underground manholes
- 3,200 feeders & 6,000 reclosers.

PG&E's diverse electric distribution system contains large numbers of rural and suburban underground residential distribution (URD) circuits, along with an extensive underground network system in San Francisco and Oakland.

B. Organization Changes

Following the September 9, 2010 San Bruno gas pipeline explosion, PG&E initiated a major focus on infrastructure and operations improvement. PG&E split the electric and gas organizations into two separate organizations in May 2011. Electric Operations also decided to reorganize. The organization structure prior to May 2011 used nine separate functional departments. Issues under this organization included gaps in matching planning effectively with operating needs, fragmented responsibilities producing diffusion in accountability and suboptimal spans of control, and inefficient work execution. PG&E implemented the new organizational structure shown below in January 2012. This structure's five departments streamline the LOB's operations.

Revised Electric Operations Organization



PG&E expected this reorganization to improve visibility and accountability for system safety, to enhance compliance focus and results, to improve work execution, and to increase efficiency. Some of the key design features of this reorganizational structure included:

- Distinct groups for transmission and distribution
- Strategic layers for asset strategy, compliance, and business management
- Centers of excellence for engineering, design, and project management
- Accountability by distinct work types to ensure ownership of results
- Central resource planning with selectively local scheduling
- Distinct customer group focused on meeting customer needs for both gas and electric businesses.

One of the new work units formed is Electric Distribution Asset Strategy and Reliability. It forms part of the Asset Management group. This unit exists to address strategic asset management plans for aging assets. This role represents a major element of plans to improve system safety by reducing equipment failures. PG&E does not have a formal asset management program in place. The Company is currently assessing the PAS 55 asset management system for implementation. PAS 55 provides an asset management process with systematic and coordinated activities and practices through which an organization can manage its assets optimally and sustainably, considering performance, risks, and expenditures over their life cycles.

We found that the revised Electric Operations organizational structure is better positioned to address aging infrastructure and system safety issues. A number of features of the new organization provide more focus on aging distribution infrastructure and system safety issues.

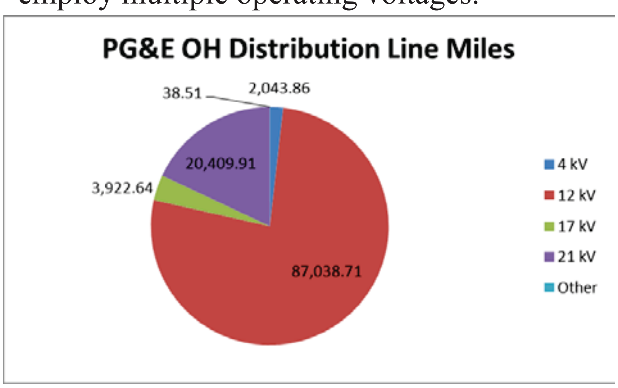
The separation of responsibility for managing gas and electric assets provides more focus on electric issues affecting safety, reliability, and other goals. The separation of transmission operations from distribution operations further increases the focus on electric distribution assets. The Asset Management group brings a more strategic approach to asset management.

C. Infrastructure Issues

Legacy infrastructure issues present challenges to varying degrees. It is a rare occurrence to find a major utility without any of these types of issues. The development of these issues might arise from a number of possible causes. A good example of a legacy issue is the distribution primary line voltage the utility uses to operate its system. Prior to WW II, 4 kV (4160kV Grounded wye/2400 volts) represented a common operating voltage for many small utilities. It is still in use today, both as a small system delivery voltage and also a usage voltage for large customers. These typically four-wire systems operate with three-phase conductors and a neutral. They could also take the form of a delta three-wire system without a neutral.

Over the years utilities have commonly found 4 kV systems too limiting in their ability to handle increasing amounts of power. Generally, 4 kV is considered today an obsolete operating voltage for a major utility. Many utilities have converted their 4 kV systems to a higher voltage, although some may still operate small 4 kV portions. The 12 kV level became the next higher common distribution voltage commonly chosen by utilities. However, in the past, standard voltages had yet to evolve. As a result many different, but similar operating voltages were selected.

Operating with voltages that are not optimum is a challenge for the industry. Overall replacement would be extremely difficult and costly. Many utilities, such as PG&E, therefore typically employ multiple operating voltages.



Two legacy PG&E issues raise system safety concerns. PG&E employs several distribution primary voltages. The first such concern arises from its unigrounded 12,470 volt three-wire system. A unigrounded system is only grounded

at one primary voltage level point, which in PG&E's case is at the substation transformer. The circuits extend from the substation as part of a three-wire system (three phase conductors). A neutral conductor is not installed. This 12 kV system serves as the predominate voltage on the PG&E system (see the accompanying chart). Very few utilities use similar three-wire systems. The vast majority of the distribution systems put in place in the past forty years comprise four-wire, multi-grounded systems.

Clearing ground faults on the three-wire unigrounded system can be more problematic, when compared with multi-grounded, four-wire systems. On PG&E's 12,470 three-wire system, a wires-down situation (a broken wire contacting an object or the ground) will often remain energized until a Troubleman arrives and disconnects the power line source of feed. The resulting time lag until de-energization can create hazardous situations. PG&E's wires-down investigations show that, on average, multiple times daily, and thirty six percent of lines presently remain energized until the Troubleman arrives. Any downed power line is a hazard to the public until it has been grounded, even if the ground fault is cleared by an upstream protective device. The hazard arises from back feed from motors and generators. Hazards become much more pronounced when lines remain energized on the ground. This phenomenon on PG&E's extensive 12,470 volt three-wire system has contributed to a number of fatalities and injuries.

The second legacy issue of particular safety concern arises from the large amount of small size obsolete conductor remaining on PG&E's system. PG&E has 113,000 circuit miles of primary voltage overhead distribution conductor. A large portion (22,206 miles, or 19.6 percent) takes the form of #6 copper (Cu) conductor. This conductor was once popular, but is now recognized as obsolete, due to its small size. Such a small conductor becomes more subject to breakage as it ages. Three factors contribute to breakage risk. First, over many years of service, conductors will experience numerous situations of arcing together. High winds or lightning strikes are principal causes of arcing. These occurrences cause small pits in the conductor. Larger conductors can withstand this type of pitting without losing as material an amount of strength. Second, small copper wire anneals at lower fault current levels than does a larger conductor. Annealed copper

becomes brittle and loses its strength. Third, a small conductor has a relatively low rated breaking strength. PG&E presently only purchases this conductor for replacement applications. PG&E also has 47,542 miles (41.9 percent of 113,000 circuit miles of primary voltage overhead distribution conductor) of #4 ACSR conductors (Aluminum Conductor Steel Reinforced) on its system. This type of conductor also raises safety concerns. ACSR conductor used a steel reinforcement core, usually with a zinc coating. Bimetallic corrosion between the aluminum and the zinc on the steel core in salt air makes ACSR conductor a suboptimum choice along coastal areas, where its use is no longer recommended.

Aging infrastructure represents a common utility industry issue. Equipment is not designed to last forever. Assets do not have unlimited lives. Utilities should address asset maintenance through continuous processes that address sustainability in a strategic manner. Unfortunately, such practices have not been commonly found in the industry. It has proven easy to put off replacements to save funding. Delays in replacements build the need for major response efforts to critical levels, as response can no longer be deferred. Asset replacement gaps can become too large to bridge without cost and often sacrifice to other goals. Drastic increase in repair, replacement, and maintenance funding has often been the result.

For electric distribution utilities, the aging infrastructure gap is a pitfall that has been difficult to avoid. This is due to several factors.

- Long service lives: A large portion of electric distribution assets are designed to provide safe, reliable service for extremely long periods. Distribution poles and conductors can last up to or over 100 years. Transformers can last over 50 years. Underground cable has a 40 to 50 year operating life. Stretching out the operating life of these assets produces a large amount of old assets operating ever closer to the brink of failure.
- Expansion has slowed: The 1950s to 1970s were a period of strong economic expansion. Much of the older infrastructure was replaced during this period. Utilities no longer face this type of growth. Assets must be replaced under maintenance planning programs rather than being forced into retirement due to load growth. In addition, the infrastructure added in the 1950s is now entering old age, and must be replaced.

- Funding priorities changed: With the advent of computers and lifestyle changes, the reliability levels of the past decades (30 or 40 years ago) have become no longer acceptable. Funding priorities were directed to reliability improvement projects and new technology. Aging infrastructure was not a priority.
- Replacement costs are high: The replacement costs of many electric distribution assets are much higher than their original cost. Inflation is one factor driving this increase, and is by itself, a major factor. Another factor increasing costs is that replacements must now often be replaced under energized conditions. Most of the original wood pole and conductor infrastructure was installed before lines were energized. Pole and conductor replacement must now be performed while the lines are energized at thousands of volts. This is a delicate and skilled job process that must be conducted under a number of safeguards in order to avoid injury. It is common for the cost of an energized pole replacement to be more than double the cost of a non-energized installation.

The combination of these factors makes it difficult to reverse an aging infrastructure trend. If allowed to develop, the financial gap becomes an obstacle requiring significant funding levels to overcome. Safety risks can also grow. The primary tool for avoiding this pitfall is a strategic infrastructure plan that addresses all major assets. An asset management approach will ensure that adequate provision is made for future requirements and obligations.

We recommend the establishment of a formal asset management program in Electric Operations. Aging infrastructure is best addressed by having a strategic asset management program in place. These types of programs, such as the PAS 55 program, force a detailed and thorough condition assessment survey of the major assets. These types of formal programs also take failure modes into consideration. Long term sustainable plans can then be prepared to address the asset conditions. A sustainable asset management will mitigate system safety risks from aging infrastructure, which constituted a major portion of the safety items in this GRC.

We also recommend that PG&E treat aging infrastructure as an enterprise-level risk. Maintenance of the assets should be a continuous process conducted in a sustainable strategic manner. It is far too easy to put off the replacement to save maintenance funding. As the

replacements are delayed, the magnitude of the financial implications of getting behind becomes too severe to overcome. Safety risks can also develop. The primary tool for avoiding this pitfall is a strategic infrastructure plan that addresses all major assets. An asset management approach will ensure that adequate provision is made for future requirements and obligations.

D. Electric Operations Risk Program

1. Enterprise Risk Management from 2006 to 2011

PG&E started an ERM Program in 2006, with the goal of identifying and managing top Enterprise-level risks. A dedicated ERM principal managed the program, drawing support from a team (in part-time roles) from across the enterprise. The program used a two-year cycle of risk identification and mitigation. PG&E identified potential risks through brainstorming sessions, which led to development of a list of enterprise-level risks.

The resulting list of risks was presented to the officer team, which voted on the final list. PG&E classified risks as enterprise or as operating level. Enterprise-level risks underwent formal reviews by upper management. Significant operating risks not classified as enterprise-level were managed by the appropriate officer owner, but did not undergo formal review. Each enterprise-level risk and operating risk was assigned to an Officer as the owner. For each risk, an individual within the applicable Officer's line-of-business was assigned responsibility managing that risk as part of the individual's overall responsibilities.

This process produced the identification of three Electric Operations enterprise-level risks associated with system safety. These risks appeared on every risk list from 2006 to 2011. The names changed from year to year, but the risks remained in essence the same.

Electric Operations Enterprise-Level Risks

2006	2008	2010
Gas and Electric Distribution Safety Conditions	System Safety	System Safety
Seismic	Seismic	Seismic and Tsunami
Urban Fire	Urban Wildland Fire	Wild Fire

PG&E has occasionally revised the wording of the risk definitions. The current definitions are:

- *Seismic & Tsunami:* The occurrence of a large-magnitude earthquake that would threaten worker and system safety, cause unacceptable damage, and hinder timely response to emergency conditions or timely restoration of gas and electric utility service.
- *Wildfire:* Risk from wildfires resulting from PG&E's activities or asset contact with vegetative fuels.
- *System Safety:* A system condition that PG&E knows, or should reasonably know, could cause a hazardous event, but does not take expeditious or sufficient action to mitigate.

In response to the identified enterprise-level risks, Electric Operations assessed the risk drivers and developed mitigation plans. Electric Operations prepared and presented a wildfire mitigation plan to the Board of Directors on December 19, 2006. The conclusion of the mitigation plan was as follows:

> *While the probability may be low that a major urban wildland fire could be caused by PG&E, the consequences are potentially very high. In addition to the risk management activities already in place, PG&E has identified additional actions to potentially reduce the probability of a fire caused by PG&E, and improve PG&E's emergency response capability. A plan has been initiated to evaluate and implement these actions and to identify additional risk reduction opportunities.*

The additional planned actions included:

- Performing additional patrols and inspections in the highest risk areas prior to the 2007 fire season
- Employment of eight arborists
- Modifying training programs in 2007 to enhance wildland fire content.

Electric Operations updated the wildfire mitigation plan in February 16, 2010. The conclusion of this mitigation plan was as follows:

> *Events in Southern California have served to highlight the risk of an urban wildland fire to utilities operating in California. PG&E continues to learn from*

the Southern California utilities' experiences, and continues to make progress to mitigate this risk.

In 2007 PG&E prepared a Seismic Risk Management Plan. Since its 1985 inception, the PG&E Geosciences Department has provided guidance for the Company's seismic risk management program. This program's six major elements included dedicated staff, budget, and accountability. This program allowed PG&E effectively to manage earthquake risks and comply with the intent of the California Earthquake Hazards Reduction Act. The conclusion of the mitigation plan was:

> *PG&E recognizes that seismic risk is a fundamental element of our operations. Risk management activities have been implemented to reduce the risk to our physical facilities, and to support our ability to respond effectively to, and recover from, seismic events.*

On September 18, 2007, ERM presented a Gas & Electric System Safety Risk Management Plan to the Board of Directors. The mitigation plan's conclusion was:

> *As a result of the ERM review, the Utility has identified additional steps to be taken in order to enhance the safety of our gas and electric T&D systems. These steps are expected to address deficiencies that have been raised by employees or that have been highlighted by recent system safety events. Information obtained through evaluations of system safety events will continue to be fed back into the ERM process for additional analysis.*

The additional steps included the following key activities:

- Implementing an Effective Asset Registry Program
- Improving Tracking of Program Implementation
- Emergency Response
- Analysis of Key Information Sources:
- Implementing a Gas Distribution System Integrity Program.

In alignment with ERM guidance, Electric Operations historically used a spreadsheet risk assessment tool for the documentation and analysis of enterprise risks prior to 2012. ERM

labeled this spreadsheet as a "Template 3." ERM did not actively edit or maintain the historic Template 3 spreadsheets, but did review them during Electric Operations' regular recurring analyses of enterprise risks. Electric Operations completed the last active Template 3 for System Safety risk in May 2011. Liberty's review of this template noted that the risk assessment included an analysis of specific threats, high consequence event risk drivers, inherent risk impact ratings, residual risk ratings and evaluations of all existing and proposed mitigation efforts. However, the analysis was for an explosion or fire risk caused by electrical transmission components only. Distribution components were not considered.

2. Changes Following San Bruno

On September 14, 2010, just five days after San Bruno, ERM presented a System Safety Risk update to the Board of Directors. This presentation's treatment of System Safety risk defined a system safety event is defined as:

- A single significant event occurring in a defined high population density area associated with gas or electric transmission and distribution (T&D) facilities; or
- Multiple significant events, independent of geography, resulting in fatalities or severe injuries and occurring within a short to medium time period.

For electrical facilities, ERM gave an example of such events. Explosions or fires could be caused by:

> *Underground electric T&D equipment (in vaults and under manholes), energized oil-filled equipment in substations, aged equipment that has not been replaced, or known defective equipment that has not been taken out of service.*

ERM cited as an additional planned action regarding electrical facilities the establishment of an inventory of aging high-risk electric system assets and an associated work plan for replacement.

Early 2011 witnessed much change in the Electric Operations organization. Risk assessment activities at that time occurred on two tracks. In 2011 PG&E decided to overhaul its Enterprise Risk Management program to focus on operational risks. This track created a formal approach to risk assessment. A second track revolved around the Electric Operations Improvement Plan. This

track was associated with the operational reorganization and improvement within Electric Operations, and involved a less formal risk assessment and a more immediate focus on actions to mitigate known risks. We discuss these two tracks separately below.

In 2011 PG&E decided to overhaul its ERM program as discussed in Chapter II of this report, in order to focus better on operational risks. Electric Operations followed this new program. In September 8, 2011 Electric Operations developed an Improvement Plan. The next section of this report discusses that plan in some detail. With respect to system safety and risk assessment planning, the plan contained an action identified as "Implement risk-based framework." This item called for the LOP to develop and implement methods to identify and prioritize system safety risk, and to formulate strategies to mitigate the occurrence and impact of safety events. The action also called for allocation of resources based on probability of occurrence and severity of impact, informed by asset characteristics, geography, and population density. The timeframe for developing and implementing this risk-based framework was 2012. Throughout the 2012 period Electric Operations started on its journey to develop and implement this framework.

In December, 2011, PG&E management instructed the LOBs to form their own Compliance and Risk Management Committees (CRMC). The first meeting of the Electric Operations CRMC occurred on February 17, 2012. At that time Electric Operations also started developing a Risk Register of the business unit's operational risks.

Additional meetings of the Electric Operations CRMC occurred throughout 2012; *i.e.*, in March, April, May, July, and September. Electric Operations adopted a working definition of System Safety risk, which the unit used throughout the conduct of its risk management activities in 2012. This definition is reflected in the RPC updates and Electric Operations Compliance and Risk Committee updates on System Safety risk. This definition includes the Board definition; however, it provides additional clarity around the potential areas of concern; *e.g.*, personal injury or fatality (public or employee). It is as follows:

> *A system condition associated with electric transmission, substation, or distribution facilities that could directly lead to personal injury or fatality of either the public and/or employees. The risk is that the Utility knows, or should*

reasonably know, about such a condition but does not take expeditious or sufficient action to mitigate it.

In March 2012 management directed the LOBs to prepare a three-year improvement plan as part of their ERM activities (S1 playbook). Electric Operations already had a three year improvement plan in place titled the Electric Operations Improvement Plan.

On November 1, 2012, the Electric Operations officially published the unit's Risk & Compliance Committee Charter. In December the Electric Operations RCC released its first register of key operational and operational risks. At that time the items on this register were still under evaluation and review. This risk register is shown below.

Initial Electric Operations Risk Register Items

Enterprise Risks	Key Operational Risks	Operational Risks
Seismic	Electric substation physical reliability and security[1]	OH Conductor –Wires Down
Wildfire	Disaster recovery[1]	Structural Failures (*e.g.*, Poles)
System Safety	Business continuity[1]	Oil-filled switches (*e.g.*, TGRAM/TGRAL)
	Encroachments (transmission and distribution easements) [1]	Network transformers/protectors
	Qualified workforce[1]	Work procedure errors
	Co-located electric substations and gas transmission	Car-pole accidents
	Catastrophic substation equipment failure	T/D cable termination failures
	Fire in indoor urban substation	Third party access to facilities
	Dig-in to underground transmission	Joint poles or joint trenches

1. These items were identified as risks prior to the advent of the Operational Risk Management framework.

The Electric Operations Improvement Plan has focused Electric Operations' recent actions to mitigate safety risks, particularly with respect to system and public safety and employee safety. PG&E did not begin that plan with a formal assessment and analysis of risk and no risk-based plan existed within Electric Operations through the time of GRC forecast preparation.

The Improvement Plan arose from a June 21, 2011, Electric Operations presentation of a sixty-day turnaround plan to top management. This plan included the development of a three-year improvement plan, calling for development of a risk-based framework and an organizational redesign. In developing this turnaround plan, Electric Operations defined what was working well and which areas needed improvement. The unit identified five focus areas: Reliability, Safety, Compliance, Customer Satisfaction, and Work Efficiency. The Electric Operations Improvement Plan's treatment of system safety contained the following high level categories:

- *Implement risk-based framework:* Develop and implement methods and approaches for identifying and prioritizing system safety risk; formulate strategies to mitigate occurrence and impact of safety events; allocate resources based on probability of occurrence and severity of impact, informed by asset characteristics, geography, and population density; actively seek and incorporate field concerns in allocating resources.
- *Benchmark to know what success looks like*: Benchmark in and outside the utility industry to better inform risk-based methods and approaches.
- *Continue "no regrets" actions:* Mitigate known issues including San Francisco network deficiencies and wildfires.
- *Improve data quality:* Use technology to improve ability to track, analyze, and maintain accurate information to ensure use of results to refine safety strategies.
- *Emergency Response:* Use technology and better coordination with local emergency response to limit impact of any safety events.
- *Engage customer community:* Use outreach campaign to raise customer awareness of electrical safety to prevent third-party contacts.

The plan also sought to use existing knowledge of enterprise risk to inform asset strategy. It also provided general guidance to focus on incidents that could reduce five "high consequence" metrics in the area of public/system safety; *i.e.*, equipment failures, wildfires, third-party contacts, dig-ins, and wires down.

The Electric Operations three-year Improvement Plan formed the basis of the 2012-2013 work plans and the 2014-2016 GRC forecasts. In addition to the asset plans in the Improvement Plan, Electric Operations concurrently developed a reorganizational plan to accomplish these

improvements. (See Section A for more detailed information on this organization.) The Improvement Plan at that point contained seven focus areas: public/system safety, employee safety, reliability, compliance, customer satisfaction, work efficiency, and technology enablers. The Improvement Plan contained system safety initiatives classified as acceleration of existing base plans or as new initiatives:

- Acceleration of existing base plan initiatives
  - Swiveloc manhole cover replacement program
  - Addressing wood pole replacement backlogs
  - Underground oil switch replacements
  - Replacing non-exempt equipment in urban wildfire areas
  - GIS/AM system project implementation
  - Mapping data quality improvement
  - Operating data in industry standard platform
  - Coordination with local agencies
- New initiatives
  - Implementing a risk-based framework
  - Replacements of network high-rise transformers
  - Data quality improvements
    - Health of records (field verification)
    - Convert Technical Library into documentation
    - Scan all records and drawings
  - Train employees on emergency response
  - Outreach campaign.

In addition to the system safety focus area mentioned above, the Improvement Plan contained six other focus areas. Several of these focus areas contained initiatives that Liberty found to also have an impact on system safety. In the reliability focus area, several of the initiatives were later connected with system safety. Testimony in the GRC work papers also later connects these initiatives with system safety. These reliability initiatives were:

- Acceleration of base plans
  - Underground cable replacement program

- EC tag backlogs
- New initiatives
  - Overhead conductor replacement program
  - Network cable replacement program
  - Increase SCADA penetration.

The focus area of technology enablers also contained an initiative related to system safety, titled "emergency management tools." Throughout the end of 2011 and in 2012 Electric Operations continued to update and refine its Improvement Plan.

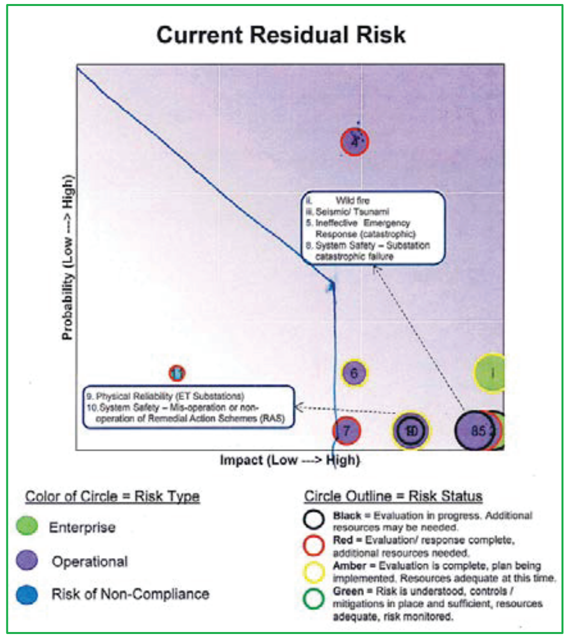
3. Current Status/Future Directions

As discussed in Section B, the centerpiece of Electric Operations' current approach to mitigating safety risks focuses on the Electric Operations Improvement Plan, particularly within the public/system safety and employee safety key focus areas. The mitigation of safety risks is largely organized around PG&E's assets and system operations. The implementation of the ORMP within Electric Operations is not complete, but is well underway. Electric Operations is continuing to identify and prioritize risks. PG&E is presently scoring these operational risks. The risk scoring requires further calibration, which PG&E anticipates will occur in 2013. In the interim, PG&E is exercising its judgment to determine which risks Electric Operations will pursue in the near term.

Risk #	Risk
i	Cyber Security
ii	Wild fire
iii	Seismic/ Tsunami
4	System Safety – Distribution Overhead Conductors (primary voltage)
5	Emergency Response (catastrophic)
6	System Safety –Transmission Overhead Conductor
7	System Safety — Distribution Support Structures (poles, framing, guying, and insulators)
8	System Safety – Failure of Substation (catastrophic)
9	Physical Reliability (ET Substations)
10	System Safety – Mis-operation or non-operation of Remedial Action Schemes (RAS)
11	Risk of Non-Compliance

On February 28, 2013, Electric Operations completed a draft of the Risk and Compliance (formerly called "Session D") templates. The Risk and Compliance module comprises the part of PG&E's Integrated Planning process that focuses on risk and compliance. Each April (beginning with 2013 as a test case), LOB personnel will discuss with senior officers their top risks, top compliance requirements, and their plans for managing them.

The new risk register list is shown in the table to the left. System safety risks are now listed on the component level rather than as one risk. The risks pertaining to distribution items are Distribution Overhead Conductors, Distribution Support Structures, and Failure of Substation (catastrophic).



Some of the risks listed in the December 2012 on the release of the first risk register are no longer present. These risks are oil-filled switches (*e.g.*, TGRAM/TGRAL), network transformers & protectors, T/D cable termination failures, and work procedure errors.

As shown in the accompanying "heat map," some of these ten risks have been evaluated while some have not. The evaluations in the risk and compliance session templates included the mapping of risk drivers and controls. Note that Operational Risk #4 – (System Safety – Distribution Overhead Conductors) has been evaluated as having a high probability and high impact residual risk. It is at a noticeably different level of risk from the others.

4. Status of Major Safety Programs

We found wildfire mitigation risk planning to be an ongoing and successful process since 2006. Well before the ERM program was identified in 2006, Vegetation Management had taken the lead in changing the vegetation program to focus on wildfire prevention. As discussed further in Section E.7 of this report, PG&E has reduced vegetation-caused wildfire ignition events. They have prepared and executed formal wildfire mitigation risk planning since the ERM program was formed in 2006. Seismic mitigation risk planning has had a similar history. Since its inception in 1985, the PG&E Geosciences Department has provided guidance for the Company's seismic risk management program. Seismic risk mitigation activities for Electric Operations distribution facilities have involved buildings and substations. This area receives more detailed treatment later in this chapter of our report.

We found that no formal risk-based assessments underlie the safety initiatives addressed in the GRC. Electric Operations has been clear about its position and direction with respect to system safety and the GRC. A risk-based framework is only emerging in Electric Operations. One of their primary Improvement Plan initiatives is to develop and implement a risk-based framework which can be used to aid future asset strategy decisions. This does not mean that safety risks have not been considered in preparing the GRC initiatives. PG&E used its existing knowledge of known system and enterprise risks to inform its asset strategy decisions. Liberty has found evidence of this throughout the detailed review of the GRC safety initiatives. Another risk-based factor in selecting the initiatives was to reduce the five "high consequence" metrics of public/system safety: equipment failures, wildfires, third-party contacts, dig-ins, and wires down.

Some progress in implementing a more structured, risk-based planning framework in Electric Operations has occurred, but it has not been marked by rapid progress. Electric Operations has been cautious in formal risk assessment identification and scoring of the risk. They have lagged behind the other LOBs in implementing ORMP. However, the unit has made progress according to the schedules set by the ERC and is on track in implementing ORMP. The program appears to be headed in a good direction and appears to have a generally sound basis.

The operational risks are now more narrowly defined, and targeted towards the electric incident history. Since the original improvement plan was issued in September 2011, PG&E's recognition of the overhead primary conductor risk has markedly improved.

E. Electricity Distribution Project and Spending Analysis; GRC Exhibit 4

1. Background

The financial forecast for the GRC is well documented in the testimony and work papers. The expense forecast for 2014 is $60.8 million higher than 2011 recorded costs. The primary drivers PG&E cited are improving system safety through increased expenditures for vegetation management, line maintenance, and asset and records management systems. The capital forecast of $1.770 billion in 2014 is $400 million higher than 2011 recorded costs. The primary drivers

PG&E cited are system safety, reliability and automation, replacement of assets that have reached the end of their useful life, and new customer connections.

Liberty reviewed the safety and security proposals related to the electric distribution system to:

- Provide stakeholders and the Commission information on the quality and cost-effectiveness of the safety and security proposals made by PG&E
- Review PG&E's proposals and compare them to industry best practices and standards.

Among the key questions we considered were:

- Has PG&E adequately assessed the physical condition of its system (physical assets and systems)?
- Are the projects prioritized by PG&E those that will address and mitigate the risks to system safety identified in the risk assessments?
- Appropriateness: Is the level of funding just and reasonable to mitigate the identified risks to system safety?

PG&E has not quantified the dollar expenditures of "safety enhancements" in its GRC because of difficulty in forming a precise and mutually exclusive definition of safety. As discussed earlier, PG&E considers safety to be one of three central pillars for planning its operational commitments. Safety forms a core element of PG&E's mission and values. Moreover, for electric operations, safety and reliability (another core mission element) are strongly intertwined.

	Dollars in Thousands					
	2012	2013	2014	2015	2016	Source
Total Electric Distribution Capital Forecast	1,465,000	1,591,000	1,770,000	1,827,000	1,909,000	Exh. (PG&E-4), Ch. 1, Page 1-20, Lines 21-24
Driver - Safety	891,181	919,602	1,010,310	1,009,780	1,028,688	GRC2014-Ph-I_DR_Liberty_001_Q043Atch01[1], Line 950
Driver - Safety as a Percent of Total Electric Distribution Forecast	61%	58%	57%	55%	54%	GRC2014-Ph-I_DR_Liberty_001_Q043Atch01,Line 954
Driver - Reliability	196,554	218,896	211,700	223,148	226,745	GRC2014-Ph-I_DR_Liberty_001_Q043Atch01,Line 951
Drivers - Safety and Reliability as a Percent of Total Electric Distribution Forecast	74%	72%	69%	67%	66%	GRC2014-Ph-1_DR_Liberty_001_Q043Atch01,Line 955

Therefore, it is fair to conclude that a large majority of PG&E's forecasted Electric Operations expenditures have at least an indirect connection to safety. The accompanying table demonstrates that PG&E has taken a very inclusive approach in connecting proposed expenditures to safety enhancements, recognizing that reliability and safety are closely related. Outages, for example, have direct reliability consequences, but can also result in live wires on the ground, cut power to critical infrastructure and people with medical needs, and cause traffic accidents, wildfires and other serious safety issues.

In developing the preceding table, PG&E began from a list of capital orders that appear in the results of operations model for the 2014 GRC, and which comprises a portion of the capital expenditure forecast for Electric Operations. PG&E assigned the orders contained in the attachment to "project driver" codes (including safety) for purposes of responding to DRA Data Request 001. In assigning these codes to the orders, PG&E did not use the above definition relating to system safety (*i.e.*, a system condition that PG&E knows, or should reasonably know, could cause a hazardous event, but does not take expeditious or sufficient action to mitigate) nor did PG&E subject the items on the list to structured safety risk assessment.

2. Definitions

Our review sought to craft a set of definitions that would permit us to distinguish safety-related Electric Operations projects and programs from others. We developed the following categories, in order to avoid what would amount to a nearly all-encompassing definition of safety-related work. The categories we applied were:

- ***Safety Initiative***: A specific project outside of the normal base activities in the GRC that is primarily targeted to mitigate a safety or security residual risk. The current residual risk is not acceptable. The project or program is not currently in the base activities.
- ***Supporting Initiative***: These initiatives comprise projects or programs in support of the distribution system and distribution operations.
- ***Base Activity***: These activities fall within what is generally considered to be normal business for electric distribution. They might relate to safety, operations and/or reliability. Managed properly, the residual risk of the base activity is currently acceptable.

- ***Reliability Initiative***: A project or activity outside of the normal base activities that is primarily targeted to reliability improvements. Such initiatives may have a tangential impact on system safety. However, they are designed and managed primarily to mitigate a reliability rather than a safety risk.
- ***Operations***: These activities primarily support electric operations. They are designed and managed primarily to support operations rather than to mitigate a safety risk.

Liberty found the encompassing approach that PG&E originally took in defining GRC safety initiatives too broad to make analysis from a safety perspective practicable. Liberty asked that PG&E reclassify distribution work as follows to facilitate our analysis:

- Falls "above the base activity level" (as requested by Liberty)
- Reasonably constitutes a system condition that PG&E knows, or should reasonably know, could cause a hazardous event, in the absence of mitigation.

We recognize that a significant portion of base activity level expenditures is safety related. Examples include work associated with distribution line patrols and maintenance tags (Exhibit PG&E-4, Chapter 5), pole test and treat and pole replacement (Chapters 6 and 7), vegetation management (Chapter 8) and emergency recovery (Chapter 10).

The resultant list of GRC items which PG&E provided fell in reasonably close agreement with the listing that Liberty made by following our classification system. The table below illustrates the difference in the two listings. The percentages shown are of the total electric distribution GRC forecast (from Exhibit 4).

Liberty/PG&E Classification of Safety Expenditures

	2014 Forecast	2015 Forecast	2016 Forecast
System Safety Initiatives - Liberty	16.7%	20.0%	19.3%
System Safety Initiatives - PG&E	18.6%	23.1%	25.0%

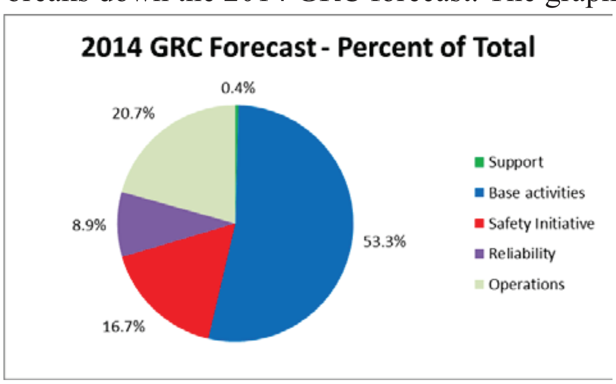
PG&E noted that its forecast for certain line maintenance work (Chapter 5 and Chapter 7) for 2012 and 2013 includes expenditures above what the Company would consider as base activity.

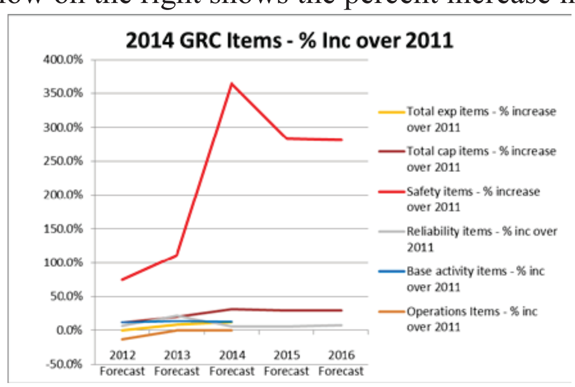
While safety related, PG&E is making these additional expenditures in 2012 and 2013 as a result of changes the Company made to the electric distribution maintenance program in 2010 (see Exhibit PG&E-4, Chapter 5, pg. 5-1, line 26). Consequently, PG&E did not include those expenditures in response to Liberty's request. Liberty agrees with this approach.

PG&E's forecast (Exhibit 4 Chapter 13) also includes several substation transformer and switchgear replacement projects. While safety related, PG&E did not include these expenditures in this response because the Company considers these projects as base-level activity, even though the absolute value of the expenditure forecast can vary from year-to-year depending on the complexity and timing of specific projects. Liberty agrees with this approach.

Finally, PG&E reiterated the strong relationship it perceives between reliability and safety. For example, while initiatives such as the Company's targeted circuit initiative (Exhibit PG&E-4, Chapter 15, pp. 15-21) and Fault Location, Isolation and Service Restoration (FLISR) projects (Exhibit PG&E-4, Chapter 15, pp. 15-20) are primarily intended to improve reliability, they also provide safety benefits. However, because PG&E is proposing such projects primarily from a reliability perspective, they were not included. Liberty agrees with this approach.

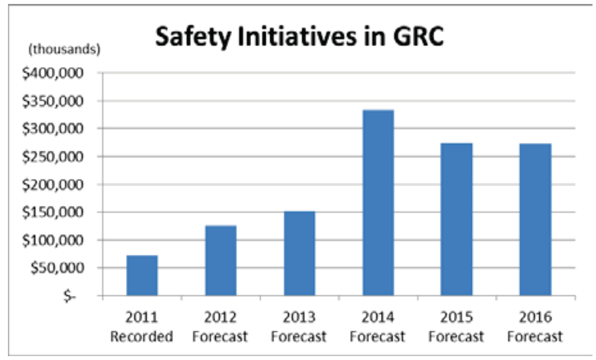
Using the safety initiatives identified from the Liberty classification structure, the next pie chart breaks down the 2014 GRC forecast. The graph below on the right shows the percent increase in

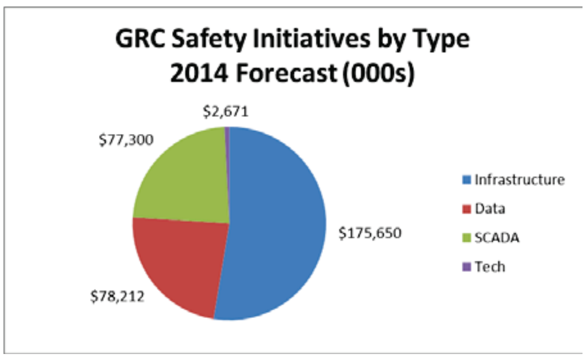


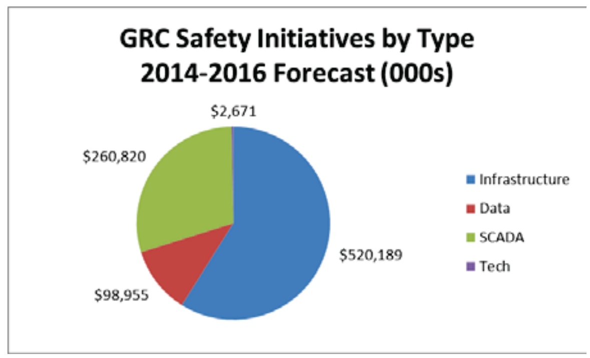


2014 forecast items over 2011 recorded data. The number of system safety projects, programs, and activities are numerous. Liberty has organized them into forty groupings in Section D below, most of them according to how PG&E presented them in the GRC work papers.

The annual safety initiative expenditures in Exhibit 4 are shown in the graph on the right. Liberty also classified each of the initiatives as either infrastructure, data, SCADA or general technology. These classifications are shown in the graphs below. As targeted in the Improvement Plan, mitigating known issues (infrastructure), improving data quality (data and SCADA) and emergency response (technology and SCADA) represent the major emphasis in these GRC items.







3. Liberty's Classification of System Safety Projects

The term "quantified risk assessment" refers to assessing the frequency of an event and its measurable consequences (fatalities, injuries, damage). Failure rates and linkages to cause must be known to a large degree. PG&E used neither as a basis of this GRC, nor was either available at the time of its preparation. In general, the data set for developing a fully quantified risk assessment for the electric distribution system will rarely, if ever, be available. The general nature of system threats, vulnerabilities, and consequences can be defined. Data to quantify the likelihood of the event might occasionally be known. The costs of risk mitigation plans should always be possible. The system impacts of risk mitigation can also occasionally be calculated. A quantification of the safety impacts of the mitigation will rarely be known.

Many of the initiatives to be evaluated comprise fairly straightforward infrastructure replacement projects. For the vast majority of the distribution infrastructure replacement, a like-for-like replacement is the only feasible alternative. For nearly all of these infrastructure replacement items, the only alternative is timing.

We found that the system safety risk mitigation items in the GRC consist mainly of aging infrastructure replacement and SCADA additions. Over 88 percent of the identified GRC system safety initiatives consist of replacing aging infrastructure and adding SCADA capability. This result conforms to the stated direction of the Electric Operations Improvement Plan to continue "no regrets" actions (mitigate known issues), enhance data quality and improve emergency response.

We also found that the system safety initiatives in the electric distribution portion of this GRC are main contributors to the increased forecast levels over 2011. The identified system safety initiatives constitute fewer than twenty percent of the electric distribution GRC items. As a group these items are over 300 percent above the recorded 2011 expenditure levels. The items identified as reliability, base operations and support are about twenty percent above the recorded 2011 expenditure levels.

4. Incident History

The tables below show CPUC-reportable electrical contact incident history. The vast majority of third-party vehicle/pole collisions are not captured in this CPUC metric, but is tracked internally. Only collisions that involve contact with energized facilities are CPUC-reportable. We made the following observations:

- Electric distribution system accounts for over 88 percent of the incidents.
- Third party contacts are by far the highest incident category at 73 percent.
- Employee contacts constitute about 22 percent.
- PG&E recorded three reportable equipment failure injury incidents since April 2004. About 7,200 equipment failures occur each year (excluding major storm days and transformer only outages).

CPUC-Reportable Injuries/Fatalities (April 2004 - April 2012)		
Cause	Count	% of total
Vehicle strikes equipment [2]	22	30.1%
Foreign object	12	16.4%
Vandalism and theft	12	16.4%
Tree trimming	8	11.0%
Accidental contact (other)	5	6.8%
Communication worker	4	5.5%
Electric work - other	4	5.5%
Aircraft	3	4.1%
Dig-in	3	4.1%
Grand Total	73	100.0%

These three recorded equipment failure incidents consisted of the following:

- August 19, 2005 - A failure occurred in the primary compartment of a network transformer. Burning oil and gasses were ejected from the vault through the manhole covers in an explosion, which damaged nearby buildings and injured a pedestrian.
- March 11, 2009 - A third-party fiber optic cable technician line-worker made contact with a down guy wire that was energized due to an overhead 12 kV line conductor that had come loose.
- April 3, 2012 - A PG&E cable splicer received an arc flash while closing a switch in a manhole. The switch catastrophically failed in the process of closing.

CPUC-Reportable Injuries/Fatalities (April 2004 - April 2012)

Cause	Count	% total
Third-Party [1]	73	69.5%
Employee related	23	21.9%
Force majeure	5	4.8%
Equipment failure	3	3.8%
Grand Total	105	100%

CPUC-Reportable Injuries/Fatalities (April 2004 - April 2012)

EO Subsystem	Count	% total
Distribution	93	88.6%
Substation	2	1.9%
Transmission	10	9.5%
Grand Total	105	100.0%

In addition to these three incidents, a fourth equipment failure incident occurred on April 20, 2012. A primary conductor failed and landed on a truck which was parked. The line remained energized. The occupant was killed when exiting the vehicle.

Vehicle strikes-equipment comprise another general category. Vehicle/pole incidents total more than 1,500 annually. Only the incidents involving electrical contact are CPUC-reportable. Car hits after which primary conductors fall down and remain energized are common. The past two years (2011 and 2012) witnessed four occurrences in which car occupants contacted energized conductors. Three involved fatalities.

We discuss employee and contractor fatalities later in this chapter. Overall, eight fatalities occurred in 2012.

- Two - Car wreck and energized downed conductors
- One – Equipment failure and energized downed conductor
- Four – Contractor fatalities (one was in the Energy Supply area)
- One – Employee fatality (motor vehicle accident)

5. Exhibit 4 – Chapters 2 To 4 – Technology, Mapping, & Records

a. Description

The table below lists the initiatives in these chapters along with Liberty's classification of each initiative. The system safety initiatives are highlighted in yellow.

GRC Exhibit 4 Technology, Mapping, & Records Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Safety per PGE & Liberty	Electric Operation Technology	2	Emergency Response Tools (electric & gas)	Cap	2F				$ 2,404		
Safety per PGE & Liberty	Electric Operation Technology	2	Emergency Response Tools (electric & gas)	Exp	JV			$ 1,499	$ 267		
Safety per PGE & Liberty	Electric Operation Technology	2	Data Historian for Electric Distribution	Cap	2F				$ 12,278	$ 10,940	$ 983
Safety per PGE & Liberty	Electric Operation Technology	2	Data Historian for Electric Distribution	Exp	JV			$ 365	$ 206		
Safety per Liberty	Electric Operation Technology	2	Outage Reporting and Analysis System Replacement	Cap	2F			$ 3,258	$ 4,516		
Safety per Liberty	Electric Operation Technology	2	Outage Reporting and Analysis System Replacement	Exp	JV			$ 235	$ 362		
Operations	Electric Operation Technology	2	Closed Loop SmartMeter™ Outage Management Integration	Cap	2F					$ 2,904	$ 2,892
Operations	Electric Operation Technology	2	Closed Loop SmartMeter™ Outage Management Integration	Exp	JV					$ 1,181	$ 1,175
Operations (Safety per PGE)	Electric Operation Technology	2	Advanced Applications for Distribution Control Centers	Cap	2F					$ 3,811	$ 5,661
Operations (Safety per PGE)	Electric Operation Technology	2	Advanced Applications for Distribution Control Centers	Exp	JV					$ 405	$ 602
Operations	Electric Operation Technology	2	Work Design and Management Projects	Cap	2F		$ 3,100	$ 4,770	$ 7,384	$ 14,613	$ 9,514
Operations	Electric Operation Technology	2	Work Design and Management Projects	Exp	JV		$ 2,118	$ 2,847	$ 6,090		
Operations (Safety per PGE)	Electric Operation Technology	2	Workforce Mobilization & Scheduling Projects	Cap	2F		$ 754	$ 13,287	$ 15,407	$ 28,118	$ 29,363
Operations (Safety per PGE)	Electric Operation Technology	2	Workforce Mobilization & Scheduling Projects	Exp	JV		$ 331	$ 1,008	$ 2,971		
Safety per PGE & Liberty	Electric Operation Technology	2	SCADA Platform Upgrade & System Enhancements	Cap	2F					$ 5,849	$ 18,250
Safety per PGE & Liberty	Electric Operation Technology	2	SCADA Platform Upgrade & System Enhancements	Exp	JV					$ 929	$ 3,292
Safety per PGE & Liberty	Electric Operation Technology	2	Electric Distribution GIS/Asset Management	Cap	2F	$ 2,889	$ 22,200	$ 32,183	$ 27,805	$ 2,000	$ 2,000
Safety per PGE & Liberty	Electric Operation Technology	2	Electric Distribution GIS/Asset Management	Exp	JV	$ 1	$ 1,449	$ 1,475	$ 1,830		
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Based Maintenance – Asset Data Analysis & Storage	Cap	2F					$ 2,461	
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Based Maintenance – Asset Data Analysis & Storage	Exp	JV					$ 838	
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Management Tool for Public Safety	Cap	2F				$ 1,466	$ 1,371	
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Management Tool for Public Safety	Exp	JV				$ 349		
Support	Applied Technology Services	3	Supports work efficiency, reliability and general safety	$ not included - minor $ among three MWCs							
Base Activity	ED Mapping and Records	4	Base Mapping and Records Management	Exp	GE	$ 3,364	$ 3,944	$ 4,563	$ 4,688		
Safety per PGE & Liberty	ED Mapping and Records	4	Field Asset Inventory	Exp	GE		$ 3	$ 2,800	$ 10,000		
Safety per PGE & Liberty	ED Mapping and Records	4	Convert paper-based records to electronic format	Exp	GE			$ 1,000	$ 14,200		
Safety per PGE & Liberty	ED Mapping and Records	4	Update electronic records to standard format	Exp	GE			$ 1,000	$ 1,000		
Safety per PGE & Liberty	ED Mapping and Records	4	Records quality assurance program	Exp	GE		$ 300	$ 400	$ 400		

Liberty's classifications did not agree with those of PG&E in three areas:

- *Outage Reporting and Analysis System Replacement:* Liberty classified this as a system safety initiative and PG&E did not. (See subsection b. below).
- *Advanced Applications for Distribution Control Centers:* PG&E classified this area as a system safety initiative; Liberty did not. PG&E felt that this initiative would enable improvements in safety, compliance, documentation, customer satisfaction, reliability and work efficiency. Liberty agrees, but also felt the initiative is primarily targeted to the Distribution Control Center Consolidation application, rather than to mitigating an identified system safety risk.
- *Workforce Mobilization and Scheduling Projects:* PG&E classified this as a system safety initiative; Liberty did not. PG&E felt that this initiative would enable improvements in safety, compliance, documentation, customer satisfaction, reliability and work efficiency. Liberty considers this initiative to be targeted primarily at work efficiency improvements.

Seventeen separate IT project groupings fall into this GRC chapter. Liberty requested that PG&E classify these projects as a new initiative, a system which is lagging behind current industry, or a system that is "broken" (dysfunctional). The next table shows PG&E's classifications. The system safety related projects are highlighted. PG&E did not classify any of the systems as dysfunctional. Liberty questions whether the two asterisked projects can be so classified.

Classifications of IT Projects

Project	New Initiative	Behind Industry
Emergency Response Technologies		X
Data Historian for Electric Distribution		X
Outage Reporting and Analysis System Replacement (Safety per Liberty)*		X
Closed Loop SmartMeterTM Outage Management Integration	X	
Advanced Applications for Distribution Control Centers (Safety per PG&E)	X	
SCADA Platform Upgrade & System Enhancements	X	
Electric Distribution Geographic Information System/Asset Management*		X
Asset Risk Based Maintenance – Asset Data Analysis and Storage	X	
Asset Risk Management Tool for System Safety	X	
Graphic Work Design		X
Capital Asset and Expense Planning System Enhancements	X	
SAP Work Management Enhancements (Plant Maintenance Module)	X	
Project Management and Reporting Toolset Enhancements		X
Customer Connections Online Tools		X
Workforce Mobilization by Field Crew or Work Type		X
Work Scheduling and Dispatch System Consolidation	X	
Scheduling Integration with Time Keeping Systems		X

For purposes of responding to this request, PG&E characterized technology projects as a "New Initiative" in cases where its technology in the area is currently up to date and the proposed project will keep PG&E on pace with industry trends. These projects differ from projects in the "Behind Industry." In those cases, PG&E currently trails existing industry practices for technology deployment; the proposed project is designed to close that gap.

Technology projects often serve an important role in improving work efficiency in complex work environments. The IT projects classified as system safety related are not necessarily able to mitigate a safety risk by themselves. Rather they are technology enablers associated with another safety project addressed in Exhibit 4. Together with the associated safety project they contribute to improving system safety.

b. Specific Initiatives

Emergency Response Technologies

PG&E classifies its emergency response technologies as lagging the industry. Rapid response to outages and unsafe conditions comprises a necessary activity for electric utilities. In particular for PG&E, the percentage of downed energized conductors that occur (36 percent) makes rapid response essential. The most critical improvement in this initiative is the addition of an Automated Crew Callout tool, which is becoming a standard feature in the industry. Rather than manual telephone dialing, these systems automate the callout operations. They provide the ability to assemble a line crew for outage response more quickly. Where downed conductors remain energized, first responders cannot begin their work until the lines have been disconnected and grounded. The number of fatalities that PG&E has experienced makes this enhancement a material contributor to system safety, in both Liberty's and PG&E's judgment.

Data Historian

The current, legacy PG&E data historian system lags the industry. This initiative will replace it with a commercial, industry-standard software system. The data historian will need to be increased to keep up with the increased SCADA functionality, which mitigates a large safety risk. These systems record time-stamped data for analysis of events.

Outage Reporting and Analysis

Liberty classifies the outage reporting and analysis system as a safety related initiative. PG&E did not classify it as a safety initiative in its response to Liberty. However, PG&E did mention the system safety benefits of the initiative in their work papers. Liberty also considers the current tool to be dysfunctional, rather than just behind the industry. PG&E currently uses legacy tools and manual processes to produce simple outage reports. The new system under development will increase automation significantly and it will interact with other IT systems such as SCADA, Distribution Management System (DMS) and GIS. PG&E is currently implementing the new system. The GRC contains expenditures in 2014 to complete the implementation.

The limited functionality of the current outage reporting system hinders system safety improvement. In a simple request for conductor failures by wire size for years other than 2010, PG&E gave the following response:

> *Regarding conductor failures by wire size, PG&E's OUTAGE database does not currently track this information and therefore the failure data is not readily available. The data used to produce 2010 information involved an engineer working many weeks to manually research each outage, identify the exact fault location, and consult PG&E's load flow model to determine conductor size.*

SCADA Platform Upgrade

PG&E classifies its SCADA platform upgrade as a new initiative. This initiative addresses how SCADA information (such as status and operating data) is gathered and displayed for the system operators. As the number of SCADA devices grows, associated hardware and support must also grow. A portion of this initiative addresses hardware items, such as servers and processors. Another portion centralizes the SCADA network operations. One important upgrade to keep up with industry technology trends is the capability to incorporate IP-based (Internet Protocol) devices. Many of the field devices are now migrating to IP-based communications. This initiative adds this capability.

Electric Distribution GIS

This initiative is the most costly of the group. It has been underway for several years. The funds in the GRC will complete the majority of this new system in 2014. The lack of a functional asset

registry system was a major finding mentioned in the IRP report. PG&E classifies this system as being behind the industry. Liberty considers it to be dysfunctional.

The current mapping system GEMS (Gas and Electric Mapping System) is strictly image-based. PG&E has built no asset intelligence into it. SAP houses the asset information. A third electrical connectivity system must also be used to manage the system. The new GIS system integrates these data systems into one, in order to support mobile technologies, system modeling, reporting and analysis, and overall asset management.

Asset Risk Based Maintenance

PG&E substations and the underground network have a separate CBM (Condition Based Maintenance) monitoring system and software tool. The system is already integrated with the SAP asset and maintenance registry. This initiative will integrate the data with more IT systems such as SCADA, DMS (Distribution Management System) and SAP work management systems.

Asset Risk Management Tool

This tool is conceptual at this stage. It will eventually include a software tool that can use inputs from the new technology systems being implemented to focus on the localized factors affecting system safety. The tool as envisioned will provide an integrated asset risk analysis tool for work planners and asset managers.

Mapping and Records

Many of the mapping records at PG&E are paper-based. The IRP report contained specific recommendations on improving the asset records at PG&E. This initiative is a part of implementing those recommendations. Electronic record conversions are included in this initiative. Most of these records are substation records. It also includes a field asset inventory of the overhead and underground distribution system, which is a critical part of implementing the new GIS system.

c. Justification

As we proceed through each category of distribution safety and security initiatives, we will in this section answer the following questions:

- Were they supported by structured risk assessments
- Did the GRC filing support them with costs benefit analysis

- Will they mitigate safety risks
- Can one determine the degree of mitigation?

We did not find the initiatives here to be derived from or supported by structured risk assessment. Moreover, the GRC does not lay a foundation for justifying them on a cost/benefit basis. We did conclude that the technology safety initiatives contribute to mitigating system safety risks in asset records, information management systems, and emergency response. Technology projects are increasingly important in improving work efficiency in today's complex work environment. Poor technology is frustrating to use. The management and monitoring of a widespread electrical grid without the use of proper technology would increase system safety risks. Overall, the initiatives improve system safety risk levels. The degree to which they do so cannot be determined from the GRC or from other information made available by PG&E.

6. Exhibit 4 – Chapter 5 - Electric Distribution Maintenance

a. Description

The table below lists the initiatives in this chapter along with Liberty's classification of each initiative.

GRC Exhibit 4 Distribution Maintenance Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Electric Distribution Maintenance	5	Patrols and Inspections	Exp	BF	$ 44,887	$40,755	$46,084	$46,286		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Enhanced wildfire patrols	Minimal $ included in Exp BF above							
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Overhead	Exp	KA	$ 41,083	$51,386	$52,455	$36,340		
Base Activity(Safety per PGE)	Electric Distribution Maintenance	5	Idle facilities investigations	Exp	KA		$ 1,831	$ 2,319	$ 3,819		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	PM & Repair - IR Inspections and Tags	Exp	KA			$ 6,600	$13,500		
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Underground	Exp	KB	$ 18,354	$23,877	$24,853	$13,753		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	UG Barcode Enclosures	Exp	KB		$ 600	$ 1,000	$ 2,000		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	UG Switch Replacement Program	Exp	KB		$ 1,000	$ 1,500	$ 1,500		
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Network	Exp	KC	$ 7,930	$ 6,582	$ 6,193	$ 5,992		
Base Activity	Electric Distribution Maintenance	5	Maintenance of Other Equipment	Exp	BK	$ 2,353	$ 2,645	$ 2,713	$ 2,713		
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Overhead	Cap	2A	$ 93,980	$86,999	$85,062	$66,186	$58,246	$ 58,670
Safety per PGE & Liberty	Electric Distribution Maintenance	5	IR - Switch Replacement	Cap	2A			$ 750	$ 750	$ 450	$ 450
Safety per PGE & Liberty	Electric Distribution Maintenance	5	IR - Conductor Replacement	Cap	2A				$15,000	$30,000	$ 30,000
Base Activity(Safety per PGE)	Electric Distribution Maintenance	5	Idle facilities removal	Cap	2A		$ 6,450	$22,866	$26,550	$ 5,250	
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Underground	Cap	2B	$ 31,440	$28,588	$33,501	$23,416	$23,343	$ 23,526
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Underground Oil Switch Replacement	Cap	2B			$ 1,000	$25,000	$25,000	$ 25,000
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Network	Cap	2C	$ 203	$ 594	$ 1,110	$ 1,113	$ 1,050	$ 1,111
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Swiveloc manhole covers	Cap	2C	$ 3,640	$ 5,280	$ 4,500	$ 3,500	$ 3,500	$ 3,500
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Network transformer replacement (high-rise & others)	Cap	2C	$ 6,381	$10,011	$ 6,193	$ 6,700	$ 5,400	$ 4,400
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Network SCADA safety monitoring	Cap	2C	$ 8,236	$ 2,247	$ 5,056	$ 8,000	$ 7,500	$ 7,500
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Network Condition-Based Maintenance	Cap	2C		$ 1,445	$ 1,000	$ 300	$ 75	$ 75

Liberty's classification of the idle-facilities initiative in terms of safety did not agree with the PG&E classification. PG&E classifies Idle Facilities Investigations and Removals as system safety initiatives. As is true for many other items in the patrol and inspect program, there exists a backlog of idle facilities that have been identified but never resolved. PG&E's database contains

approximately 22,000 pending idle facility locations for review. PG&E felt that idle facilities can result in safety hazards, mitigatable through removal or de-energization. Liberty felt that no observed or defined safety risk differentiating these lines from other lines was apparent. GO rule 95 requires lines temporarily out of service to be inspected and maintained in conditions that will avoid hazards. It also common practice in the industry to disconnect and ground an idle tap line or transformer.

b. Specific Initiatives

<u>*Patrols and Inspection Program*</u>

The industry recognizes distribution line patrols and inspections as a main defense against system safety risks. The National Electrical Safety Code sets a performance requirement for inspection of lines and equipment. It states that, "Lines and equipment shall be inspected at such intervals as experience has shown to be *necessary*." Inspections are critical to identifying system hazards, such as broken guy wires, low hanging energized conductors, broken crossarms and insulators, and clearance issues created by third parties. Reliability benefits also result from line patrols. Underlying causes can be discovered and repaired before outages occur.

General Order 165 defines the California requirements for patrol schedules and inspection schedules. "Patrol" inspections consist of simple visual inspection of applicable utility equipment and structures, designed to identify apparent structural problems and hazards. Patrol inspections may be carried out in the course of other Company business. Patrols are required annually in urban areas (> 1,000 persons per square mile) and every other year in rural areas. Rural patrol inspections cycles increase to once per year in Extreme and Very High Fire Threat Zones in certain counties. PG&E generally uses "ride-bys" to conduct patrols. "Detailed" inspections are more focused than patrol inspections. Detailed inspections involve careful examination of individual pieces of equipment and structures, using visual means and use of routine diagnostic tests, as appropriate. Where practical and useful, they can also involve equipment opening and the rating and recording of certain conditions. Detailed inspections must be conducted every three years for general underground facilities. A five-year cycle applies to overhead facilities and pad-mounted transformers. PG&E conducts detailed inspections by walking. For both the patrols and inspections, PG&E uses a paper-based process for data-gathering. PG&E inspects the pad-

mounted transformers on the three-year schedule used for other underground facilities; it does not rely on the five-year schedule allowed for them.

PG&E's Distribution Compliance Unit has design and ownership responsibility for preventative maintenance programs. The electric distribution maintenance program managers have responsibility for PG&E's distribution maintenance programs. These programs include overhead and underground distribution patrol and inspection program, line equipment testing, line equipment repair, line equipment replacement, infrared inspections on the underground system, insulator washing, corrective maintenance activities, wildfire mitigations, and streetlight repair and replacement. This responsibility includes managing program content, annual work planning, and budgeting. A field team provides direct support to each Division for GO 165 patrol, inspection, and equipment testing. Their role includes maintenance plan creation, modification, and support; patrol and inspection data capture and reporting; data analysis and support.

Prior to 2010 PG&E applied an up to 66 month deadline for completing repairs of items identified through inspection. In 2010, PG&E began implementing a new system for prioritizing notifications. The Company's objective was to complete newly identified notifications for abnormal conditions within 12 months, and to eliminate the backlog of repair items by the end of 2013. Under the previous prioritization system, PG&E could reassess notifications and extend deadlines. This approach produced a backlog of lower priority notifications.

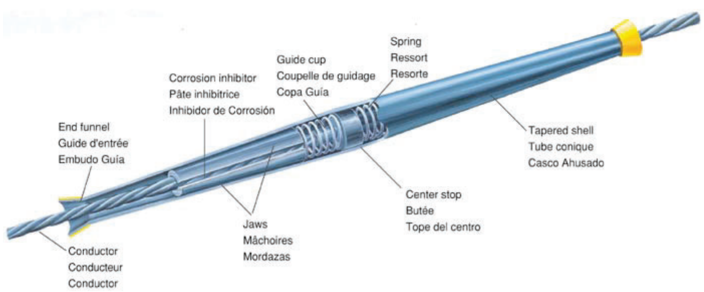
The safety incident history listed in Section E.4 would indicate that the patrol and inspection program has been effective in minimizing system safety incidents due to causes preventable by inspection processes. Only one electrical contact incident (on March 11, 2009) was due to an observable defective situation. The main defective item found during the patrols and inspections has been failed wood crossarms. About 3,200 per year were found (2007 to 2011 data). Still, about 600 fail each year and cause outages. From a wood crossarm perspective, the program is about 84 percent effective (items proactively found divided by the total of items found and items that failed) in preventing failure. Similarly wood pole data is available. About 260 are proactively found each year, and 530 fail, for an effectiveness of 33 percent. Pending pole failures are more difficult to spot. Overall, about 33 percent of PG&E's primary voltage-level

outages are due to equipment failure. This is an annual rate of 6.4 equipment outages per 100 miles. It was also noted that 32 percent of all system outages are logged as no cause found. We consider any unknown outage cause percentage over 10 percent to be high. Many of these outages could also be due to equipment failures.

This chapter also includes a modest safety initiative in the area of wildfire patrols. The Company proposes a new wildfire mitigation process for urban wildfire areas. PG&E patrols these areas annually. This initiative calls for patrolling on an early aggressive schedule, before the wildfire season starts. In addition, the overhead facilities in the areas would undergo an infrared inspection to identify any hot spots.

Infrared Programs – Switches, Connectors and Conductors

These safety initiatives contain an infrared program targeted at overhead distribution line switches and overhead conductor automatic splices. A typical automatic splice is shown in the



cutaway view. It uses internal compression springs and tension jaws that grip the conductor. There have been a number of overhead splice failures on the PG&E system. A notable example was the splice failure at Candlestick Park on December 19, 2011. Internal corrosion in splices creates excessive electrical resistance. The splices fail as a result of excessive heating in the splice, resulting in mechanical failure. PG&E estimates that 600,000 to 800,000 auto splices exist on its system. In general, utilities are finding that these types of splices have lifespans less than the associated conductor lifespan, especially in coastal areas. Today's newer automatic splices include corrosion-resistant models.

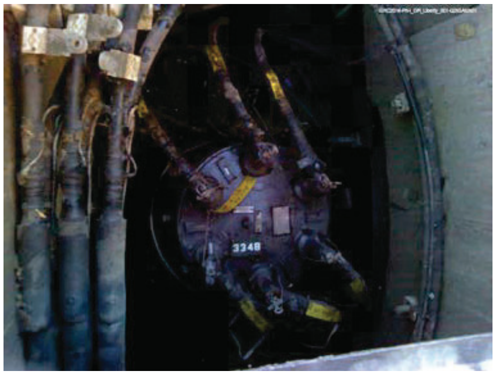
PG&E has been conducting infrared inspections on a limited, as-needed basis. The Company now proposes an infrared inspection of the entire overhead distribution system on a two-year cycle, starting in 2013. This cycle would address about 50,000 circuit miles each year. PG&E estimates that it experiences 2,000 to 3,000 overhead conductor and splice failures annually, and projects a 10 percent outage avoidance from this program. This percentage amounts to about two hot spots every 73 miles, which illustrates the needle in the haystack problem that is so often

found in searching for distribution problems. It is a common practice in the industry for utilities to infrared-inspect distribution systems on a cyclic basis. It is the best available means of identifying trouble-prone connectors.

This initiative includes several categories of expenditures. The total cost for the 2014 to 2016 period is $90.15 million. This sum includes the expense portion for only 2014. Holding the 2014 expenses constant for the 2015 to 2016 period would produce a total cost of $117.15 million for the three years. The expenditure categories are:

- *Infrared Inspection:* The portion of the program addressing scans by crews of all the circuits is an expense item. The crews will also repair some items as they are discovered. Mechanical sectionalizing switches and ganged air break switches are a common source of hot spots. If the switch jaws are not aligned properly, a hot spot will develop. Often the crew can fix the hot spot by switch adjustment. When a heated splice is found, it will be replaced by the crew. About $13.5 million per year or 34 percent of three-year program costs is forecasted for this category.
- *Switch Replacement:* Sometimes the switch contacts are burned and pitted, requiring switch replacement. About $1.65 million, or 1.4 percent, of three-year costs is forecasted for this category.
- *Conductor Replacement:* PG&E proposes to replace spans containing more than three splices. Most spans on the PG&E system use a three-phase configuration. If only one of the three wires in the span has three splices, then only one will be replaced. This replacement conductor would need to be the same wire size and type as the other two conductors to avoid sagging and clearance issues. Replacing a conductor would involve dead ending the conductor on each adjacent structure and installing two jumpers and four connectors. This program is based on single span replacement methods. About $75 million or 64 percent of the three-year costs is forecasted for this category.

<u>*Underground Oil Switch Replacement*</u>



The proposed oil switch replacement program in this GRC Exhibit 4 chapter is separate from the TGRAM/TGRAL switch program addressed in PG&E Exhibit 4 Chapter 16. The oil switches in the Exhibit 4 Chapter 16 program are commonly located in underground manholes and transformer vaults (see adjacent picture). PG&E's system includes 20,378 of these switches. These types of underground switches are common in the industry. Since 2000 the PG&E switches have experienced 259 failures with 61 involving explosion and fire risk. Thirty seven of these 61 failures involved 1970s or 1980s vintage switches. PG&E estimates about 2,500 switches are older than 1970 vintage.

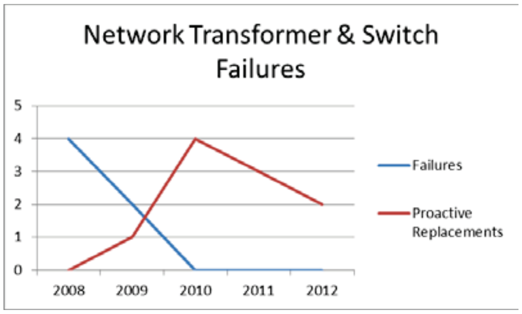
A thorough assessment will need to occur before replacements can be targeted. PG&E proposes inspection and assessment activity from 2012 through 2014, with replacements occurring primarily in 2014 through 2016. The condition based assessment would include oil level, age, type, switching configuration, corrosion, operator control, location factors, lack of an oil sight glass, and vendor/model data. PG&E started the assessments in 2012. PG&E estimates that almost 90 percent of the assessments will be complete by March 2013. The proposal forecasts replacing 1,500 switches from 2014 through 2016. PG&E estimates that two failures per year will be avoided.

PG&E also proposes to install barcode tags on about 402,000 underground enclosures. Barcode installation would occur in conjunction with normal routine inspections. Barcoding will be useful with the future mobile technology. It is common in the industry to have field barcodes for major maintenance items.

<u>*Networks*</u>

A serious injury occurred in 2005 to a member of the public due to a network incident. Hot gases from a network vault manhole explosion were released. Prior to this time the general maintenance plans for the networks, apart from the required inspections, used a "run-to-failure"

approach." As a result of this incident, PG&E developed and implemented a comprehensive network asset maintenance plan in 2008.



PG&E has twelve networks, all of which lie in the Bay area. A total of 67 primary distribution network feeders serve 1,366 network transformers. Peak network load is 440 MW. PG&E has used the SAP asset registry for the networks since 2008. Failure data has only been kept since inception of the new Asset Management program in 2008.

The network program has been successful in reducing network transformer and switch failures. Proactive maintenance replacements have been accompanied by a drop in the number of failures to zero.

Oil sampling forms the core of a sound asset management for this equipment. PG&E started oil sampling in 2008. The analysis of the dissolved gases in the oil sample comprises the basis for transformer and network protector replacement decisions. PG&E annually takes an oil sample from all oil-filled transformer chambers. The results of this testing drives scheduling of equipment for replacement. Transformer replacement decisions rely solely on gas analysis results. PG&E does not apply any age-based criteria. Protectors are now replaced at the same time as the transformer. Absent an emergency, PG&E schedules replacement for the next year. The network protector is an air insulated circuit breaker and does not contain oil.

A maintenance program also addresses the protectors. PG&E replaced many transformers in the 1980s, but did not address the associated protectors. Protectors have a 35 year life, but some date from the 1940s and 1950s. PG&E started a 100 percent internal inspection program in 2008. Workers access the inside of each protector to clean the switch mechanism, and to check contacts, relay settings, and other items. The Company uses a three year inspection cycle.

Some network transformers and protectors are located in high-rise buildings. These units pose a significant system safety risk. Risks of transformer explosion or fire in a high-rise building have substantially higher impact potentials than what applies for street-level, underground vaults. The risks of installing oil-filled transformers in high-rise buildings are no longer tolerable. Common industry practice is to install dry-type, rather than oil-filled transformers inside buildings. Failures of oil-filled transformers as they age can generate several types of hazardous, explosive gasses, including methane, hydrogen, and acetylene. PG&E has had 91 high-rise network transformers in service. Twenty five of these transformers have been replaced with dry-type units. Sixty six of these ninety-one units remain to be replaced. Using preferred dry-type transformer replacements will eliminate explosion and fire hazards. Where existing transformer rooms prove too small for dry-type units, PG&E will install single chamber units employing explosion-resistant casing. This safety initiative proposes to replace all of the remaining high-rise transformers by 2016.

PG&E proposes the use of a network CBM (Condition-Based Maintenance) system as a safety initiative. The Network inspection approach used in 2008 involved a paper process checklist followed by input into an Excel sheet. Starting in mid-2011 PG&E automated the network maintenance records into CBM (a software program using tablet PCs). Current activities involve the addition of oil analysis results. Minor levels of 2014 expenditures are proposed to complete the system additions.

PG&E also proposes a safety initiative in this exhibit chapter for the network SCADA system. PG&E's 1980s vintage network SCADA system offered some basic functionality (secondary amps, open/close, and overload alarms). It operates strictly as a monitoring system with no supervisory control. PG&E decided to upgrade the system in 2009, as part of a process to move from time-based maintenance to true condition-based maintenance. The new system can monitor more functions (*e.g.*, temperature and pressure on each oil filled chamber and oil level). It also offers some remote supervisory control capability (*e.g.*, remote protector open/close and group feeder trip function). PG&E replaced one of its 12 SCADA networks in 2012, and has scheduled a second for replacement in 2013. The Company proposed to complete all network SCADA replacements by 2017.

Swiveloc Manhole Covers

Another safety initiative addressed in GRC Exhibit 4 calls for installation of Swiveloc manhole covers. They will serve as the last "line of defense" for manhole explosions. Manhole covers weigh 200 pounds, but can still be tossed several hundred feet during an explosion. Manholes located below street grade often accumulate explosive gases, such as gasoline vapors. Cable failures can cause explosive manhole gases to ignite. PG&E experienced 15 failure incidents in 2011. Three involved explosions and manhole cover displacement. Fourteen more such incidents occurred in 2012. Three of them involved explosions and manhole cover displacement. PG&E also suffered a 2005 electric injury incident that involved manhole explosive gases.

The Swiveloc cover is designed to remain engaged to the manhole frame throughout all but the most severe explosive events. Utilities across the country now use this type of manhole cover in many major metropolitan areas. San Francisco alone has 8,800 manhole covers. PG&E installs the covers in networks and in other locations having high pedestrian traffic. The Company must mill out the manhole concrete neck to install these new covers. The Company then chains the new manhole cover frame, and bolts it to the manhole structure.

PG&E has installed these covers along parade routes and downtown San Francisco festivity areas. PG&E also installed the covers in Union Square area and Chinatown. They are proposing to install 1,800 Swiveloc manhole cover replacements from 2014 to 2016.

c. Justification

Again, we found that the GRC initiatives of Exhibit 4, Chapter 5 were not supported by structured risk assessment or justified by analyses of their costs and benefits. However, with one exception, we found them to be sound programs that appear to be effective and properly managed programs that mitigate identified safety risks.

We found PG&E's preventive maintenance patrol and inspection program to comprise a base activity that the Company has effectively managed. The industry recognizes distribution line patrols and inspections as a primary defense against certain system safety risks. PG&E has a good track record. Since 2004, PG&E has experienced only one electric contact incident from a defective condition that should have been observable during a line patrol. Liberty did not observe

any apparent safety risk gaps in this program. PG&E inspection schedules have met or exceeded the inspection timeline requirements of GO Rule 95. Liberty observed, however, that PG&E recorded 32 percent of system outages as unknown, which is high (over 10 percent). This percentage needs to be reduced in order to improve their failure data. This data collection issue underscores the importance to risk assessment of assuring that data about system conditions and events is carefully collected and maintained.

We concluded that the enhanced wildfire patrol program contributes to improving system safety by attempting to reduce wildfire ignitions. The initiative described in the current GRC comprises a moderate process improvement that will contribute to identifying possible equipment hot spots before the start of the wildfire season. Precise contributions to wildfire reduction cannot be quantified. Liberty believes, however, that the impact on wildfire reduction will be minor.

We found that the infrared inspection program contributes to system safety by reducing wires down; it also contributes to improving reliability by identifying heated switches. Overhead energized wires down comprise risk factors for both wildfires and system safety. They also form a major cause of outages.

We also found that the underground oil switch replacement program contributes to system safety by reducing explosion and fire risk. Sixty-one incidents of explosions and fires involving these oil switches have occurred since 2000. One employee injury occurred in 2012. These pre-1970 vintage switches have exceeded their operating lives.

We found the underground enclosure barcode program to be an effective contributor to employee and system safety, by simplifying field data access. This proposal represents a minor initiative to install barcode tags on underground enclosures. It is common in the industry to have field barcode for major maintenance items. Street manhole systems and sidewalk vaults are difficult and dangerous to access. This initiative improves safety by assuring the crew is at the correct location before they begin work activity to set up a safety zone and enter the underground facility.

We found that PG&E's network high-rise transformer replacement program mitigates a high consequence safety risk. Network transformers and protectors located in high-rise buildings pose a significant system safety risk. The risk of installing an oil-filled transformer in a high-rise building is no longer considered tolerable. Oil filled transformers are subject to generating several types of hazardous gasses that are highly explosive.

We found that the network CBM program contributes to system safety by improving the asset registry. In mid-2011 PG&E automated the network maintenance records into CBM (a software program using tablet PCs). PG&E has already completed the vast majority of the work. This initiative involves minor expenditure in 2014 to complete the system additions.

We found that the network SCADA program contributes to system safety by improving system monitoring and control. PG&E installed the existing network SCADA system in the 1980s. In addition to maintenance problems, the existing system has operational limitations. The system's monitoring functions are minimal. The new SCADA system will improve the monitoring capabilities in areas critical to system safety (*e.g.*, transformer temperature and internal pressure).

The Swiveloc manhole replacement program contributes to system safety by eliminating the hazard of ejected manhole covers. PG&E installs these covers in networks and other locations with high pedestrian traffic.

The exception to our conclusions that the initiatives of Exhibit 4, Chapter 5 represent effective measures involves conductor replacement under the infrared program. Portions of that replacement program compete with rather than complement the conductor replacement in Exhibit 4 Chapter 15 (addressed below).

7. Exhibit 4 – Chapters 6-8 – Pole Test/ Replacement and Vegetation

a. Description

The next table lists the initiatives in these chapters along with Liberty's classification of each initiative.

GRC Exhibit 4 Pole Test/Replacement and Vegetation Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Pole Test & Treat, Joint Utilities	6	Poles-Inventory/Test & Treat	Exp	GA	$ 6,550	$ 16,184	$ 19,251	$ 16,117		
Base Activity	Pole Replacement	7	E Dist Inst/Repl OH Poles	Cap	07	$ 89,113	$135,706	$153,498	$ 69,578	$67,912	$61,103
Base Activity(Safety per PGE)	Pole Replacement	7	Replace centerbore street light poles	Cap	07		$ 19,998	$ 6,300			
Base Activity	Vegetation Management	8	Routine Tree Work	Exp	HN	$151,600	$151,400	$153,200	$156,000		
Base Activity	Vegetation Management	8	Vegetation Control	Exp	HN	$ 8,400	$ 8,500	$ 8,600	$ 8,700		
Base Activity	Vegetation Management	8	Quality Assurance	Exp	HN	$ 900	$ 1,100	$ 1,200	$ 1,200		
Base Activity	Vegetation Management	8	Public Education	Exp	HN	$ 400	$ 400	$ 400			
Base Activity	Vegetation Management	8	Environmental Compliance	Exp	HN	$ 300	$ 300	$ 12,700	$ 12,600		
Safety per PGE & Liberty	Vegetation Management	8	Fire Risk Reduction	Exp	HN				$ 11,100		
Base Activity	Vegetation Management	8	Vegetation Management Balancing Account	Not included in this spreadsheet							

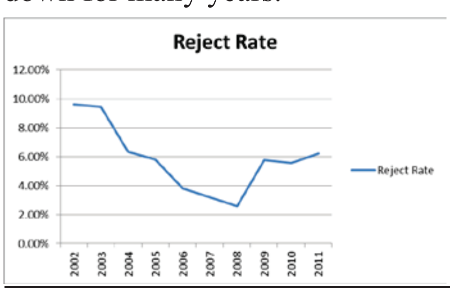
Center-bore poles are hollow core wood street light poles; they are subject to lifespans shorter than the average for solid wood poles. PG&E classifies its center-bore streetlight pole replacement program as a safety initiative. Liberty agrees that these decayed poles create safety risk; however, the Company expects to complete replacement expenditures by 2013, before the GRC rate period.

b. Specific Initiatives

Wood Pole Program – Testing & Replacement

PG&E has approximately 2.3 million wood poles on its system. Wood distribution poles comprise the structural heart of the electric distribution system. This critical system component bears close scrutiny. Liberty has reviewed the safety aspects of the wood pole program. Nevertheless, we consider the sustainability aspects by far the overriding concern when developing wood pole programs. The large safety factors built into the system generally mean that wood pool facilities will fall substantially behind the sustainability curve long before serious safety concerns occur. In other words, treatment and replacement should already be occurring before facilities begin to raise substantial safety concerns.

PG&E begins on a comparatively strong footing in addressing its wood poles. The species in service on its system include two of the most durable types (Western Cedar and Douglas fir). Moreover, their average age of 39 years is comparatively long. These factors will help hold costs down for many years.



PG&E has conducted a groundline pole testing and treatment program since 1995. The program is well into its second cycle. The 10-year cycle length is typical in the industry.

The accompanying graph shows a declining reject rate. One would expect a lower reject rate during the second inspection cycle. However, the graph could be somewhat misleading as PG&E inspects poles by geographical area. The reject rates in the geographical areas vary according to the installation history and climatic characteristics of each area.

PG&E's pole inspection and groundline treatment processes follow industry-standard guidelines. Crews perform a visual inspection from top to ground, and conduct a sound test on all poles. A partial groundline excavation occurs for all poles ten years old or greater (with the exception of Douglas fir and Western Cedar penta poles that are less than fifty years old if they have not previously been intrusively tested). PG&E performs external decay checks and, as necessary, full groundline excavations. All poles ten years old or greater are subject to internal bore and probe inspection. Rejected poles undergo a strength calculation that is done to determine they are either acceptable for further service based on standard safety factors, or unserviceable. PG&E reinforces or replaces unserviceable poles. Crews apply preservatives if the pole is to remain in service or be reinforced. PG&E does not currently have a maximum pole age limit for any type of pole.

There have been some concerns and changes to the program recently.

- PG&E added strength calculations in 2011. This feature allows for serviceable poles to remain in service for at least one more cycle.
- Prior to 2010, the local offices entered pole replacement notifications in the SAP system. Not all of the poles recommended for replacement under the test and treat program were replaced. Now the pole test program automatically generates a replacement notification in SAP that can be tracked.
- The pole testing program has fallen behind schedule. More poles are now being tested in order to catch up by 2015.
- A pole replacement backlog has developed. The old prioritization system permitted pole replacement notifications to have completion durations of up to 66 months. PG&E could reassess notifications and extend deadlines, thus creating a backlog of lower priority notifications. In 2010, PG&E began implementing a new system for prioritizing notifications. PG&E's new prioritization system classifies work identified prior to

January 2010 as backlog. PG&E plans to complete all new notification work within 12 months, which would avoid creation of any additional backlog. PG&E forecasts to eliminate the backlog by the end of 2013.

After elimination of the pole backlog, the GRC forecast assumes about 4,870 pole replacements per year under the test and treat program. PG&E identifies and replaces another 500 poles per year under its line inspection program. These two replacement sources amount to about 0.24 percent of the total population, which is not sufficient to produce a sustainable rate. Apart from its pole inspection program, PG&E replaces additional poles as lines are relocated or rebuilt. PG&E has purchased an average of 21,168 poles each year over the past ten years. This amount equates to 0.96 percent of the population.

Liberty reviewed the pole failure rate for the past five years, examining outage data. We found no significant concerns. Failure-causing outages during non-storm days run from 2.0 to 2.4 percent of total outages (not including transformer outages). The rates increase to the five percent range on major storm days. This level of increase is within reasonable expectations.

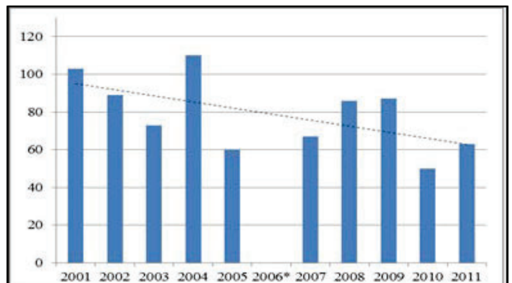
Vegetation Management

PG&E classifies wildfires as an enterprise-level risk. The vegetation management (VM) program plays a central role in managing wildfire risk. This risk in California has been a concern long before the PG&E ERM program began. About sixteen years ago PG&E's VM program was consistent with basic industry standard. Vegetation Management performed trimming on a time and material basis under cycles ranging from three to five years. Prompted by lawsuits on fires and by environmental and property damage, PG&E began an annual trim and patrol program. This program can best be described as "just in time" trimming. Rather than using a time and materials approach, PG&E moved to a trim-unit cost program. Liberty considers such unit contracts a sound method for understanding and controlling vegetation trimming costs.

The same, single work group at PG&E manages both transmission and distribution vegetation programs. A Planning group handles contract administration, quality assurance, database, billing, and customer outreach. An Operations group handles field management, organized into eight trim areas. Each area employs two foresters.

California has a number of different fire areas, with each subject to differing minimum trim standards and other regulations, including state/federal fire areas, local fire areas, FRAP areas (Fire and Resource Assessment Program), and Urban Wildland Fire (UWF) areas (PG&E-defined geographic areas that meet specific criteria of population density, ground slope, and the CAL FIRE definition of Extreme or Very High Fire Threat). PG&E's standard trimming meets the regulations in all areas. PG&E does not allow any drop below standards from one area to another.

A unit-trim contracting process allows PG&E to dictate the exact trimming for each tree. Trimming is done by circuits. PG&E pre-inspects 100 percent of the overhead power lines each year. Handheld devices enter the collected trim data. About four to six weeks after the pre-inspect work the tree contractor performs the actual trimming. Contractors trim about 1.3 million trees each year. A quality control sampling process exists. Moreover, a quality assurance audit process provides for a more detailed work review. PG&E also investigates every vegetation outage which occurs (about 4,000 per year for non-major storm days).



* From 2001 to 2005, the number of CPUC reportable vegetation incidents was collected by the Electric Incident Reporting group. CPUC decision 06-04-055 eliminated the requirement for reporting vegetation-related incidents in April 2006, and the Eclectic Incident Reporting group stopped collecting this data So, 2006 was a partial year, and it is shown as blank. Beginning in 2007, the Vegetation Management group began collecting this data consistent with the prior Electric Incident Report group approach.

The annual patrol and trim program keeps vegetation reliability indices at low (strong) levels. More importantly from a wildfire safety perspective, the vegetation-cause ignition events have shown a steady decline, as the accompanying graph shows.

Vegetation Management – Fire Risk Reduction

As demonstrated in the ERM Wildfire Mitigation Plans over the years and with the on-going CPUC rulemaking process in this area, mitigating wildfires has been a continuous improvement process. PG&E has a safety initiative titled Fire Risk Reduction in this exhibit chapter arising from the mitigation plan. For the highest one percent risk areas, PG&E proposes to inspect danger trees adjacent to the circuits over a five-year period. The ANSI A300 (Part 7) Integrated Vegetation Management standard defines a danger tree as "a tree on or off the right-of-way that

could contact electric supply lines" and a hazard tree as "a structurally unsound tree that could strike a target when it falls" (in this case, the target is the utility line).

It is common practice to remove hazard trees on distribution line rights-of-way, but not danger trees. Contractors will inspect each danger tree, check it for internal decay, and remove it if necessary. Danger trees that fail this inspection are classified as a hazard tree, and removed. Often a hazard tree is not readily apparent without a detailed investigation using sonic or intrusive bore tests.

c. Justification

Again, we did not find the initiatives of GRCV Exhibit 4, Chapters 6-8 to be driven by structured risk assessment or cost/benefit analysis, but they generally represent appropriate and effectively managed responses to underlying safety issues.

We found that the wood pole program operates as a base activity that PG&E manages effectively; no unaddressed safety risk is apparent. Wood poles comprise an important structural element of the electric distribution system. Liberty reviewed the program structure and components to verify that there were no apparent gaps in identifying and addressing safety risks. The Liberty review did not include field observations.

We also found that the vegetation management program comprises a base activity that PG&E operates effectively to minimize wildfire risks. The PG&E vegetation management program comprises an important part of the enterprise-level wildfire risk management. PG&E has a comparatively very strong program in place. Liberty reviewed the program to verify that there were no apparent gaps in identifying and addressing safety risks. The Liberty review did not include field observations.

We found that the fire risk reduction program could potentially reduce wildfire risk. This initiative consists of an aggressive tree inspection and removal program for high fire-risk areas. Many outages are caused by tree and branch failures originating from outside the rights-of-way. This PG&E program focuses on hazard tree abatement, or tree risk management.

8. Exhibit 4 – Chapters 13 to 15 – Substation Assets, Planning & Reliability

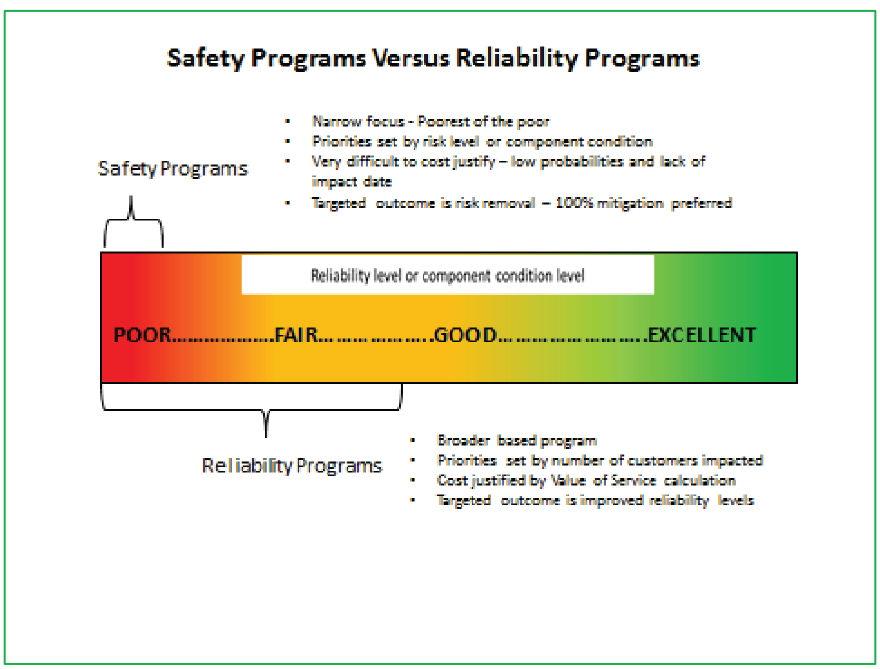
a. Description

The next table lists the initiatives in these chapters and Liberty's classification of each initiative.

CRG Exhibit 4 Substation Assets, Planning & Reliability Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Substation Asset Strategy	13	Dist Sub: Maintain & Operate	Exp	GC	$ 33,077	$ 37,572	$ 40,064	$ 40,064		
Base Activity	Substation Asset Strategy	13	E Dist Subst Repl Other Equip	Cap	48	$ 10,889	$ 9,030	$ 13,818	$ 14,059	$ 12,622	$ 13,528
Base Activity	Substation Asset Strategy	13	Switchgear Replacement	Cap	48	$ 28,125	$ 34,377	$ 33,588	$ 42,962	$ 51,500	$ 71,950
Base Activity	Substation Asset Strategy	13	Breaker Replacement	Cap	48	$ 10,165	$ 6,994	$ 7,500	$ 9,000	$ 10,500	$ 12,000
Base Activity	Substation Asset Strategy	13	E Dist Subst Repl Transformer	Cap	54	$ 44,895	$ 61,062	$ 39,051	$ 58,554	$ 53,291	$ 49,414
Base Activity	Substation Asset Strategy	13	4 kV Bank Replacement	Cap	54	$ 1,243	$ 1,267	$ 2,100	$ 6,300	$ 6,900	$ 6,300
Base Activity	Substation Asset Strategy	13	E Dist Repl Substation - Safety	Cap	58	$ 1,152	$ 875	$ 3,138	$ 3,126	$ 3,120	$ 3,110
Base Activity	Substation Asset Strategy	13	E Dist Subst Emergency Replace	Cap	59	$ 40,942	$ 27,342	$ 41,153	$ 41,011	$ 40,940	$ 41,118
Base Activity	Elect Eng – Dist Planning, Ops,	14	Opr Distribution Sys - El Eng	Exp	FZ	$ 19,603	$ 22,077	$ 23,187	$ 23,392		
Safety per PGE & Liberty	Elect Eng – Dist Planning, Ops,	14	Wire down investigations	Minimal $ included in Exp FZ above							
Base Activity	Electric Distribution Reliability	15	Base Reliability Program	Cap	08	$ 4,001	$ 3,500	$ 4,500	$ 9,580	$ 9,470	$ 10,120
Safety per PGE & Liberty	Electric Distribution Reliability	15	Overhead Conductor Replacement Program	Cap	08	$ 5,929	$ 9,190	$ 8,000	$ 32,500	$ 34,130	$ 34,509
Base Activity	Electric Distribution Reliability	15	Line Recloser Revolving Stock	Cap	08	$ 10,736	$ 8,875	$ 12,000	$ 24,420	$ 24,530	$ 25,080
Reliability	Electric Distribution Reliability	15	CORNERSTONE Rural Fuses	Cap	08	$ 37,029	$ 1,750				
Reliability	Electric Distribution Reliability	15	CORNERSTONE Rural Line Reclosers	Cap	08	$ 24,687	$ 15,072				
Reliability	Electric Distribution Reliability	15	CORNERSTONE Circuit Automation & Interconnectivity (	Cap	08	$ 3,952	$ 64,500	$ 106,050			
Reliability	Electric Distribution Reliability	15	Escalation	Cap	08			$ 705	$ 1,686	$ 1,610	$ 1,947
Reliability	Electric Distribution Reliability	15	FLISR Systems	Cap	49				$ 60,000	$ 60,000	$ 60,000
Reliability	Electric Distribution Reliability	15	Targeted Circuit Initiative	Cap	49	$ 57,259	$ 52,128	$ 52,000	$ 26,000	$ 26,000	$ 26,000
Reliability	Electric Distribution Reliability	15	Recloser Control Upgrades	Cap	49	$ 2,363	$ 2,024	$ 800	$ 1,600	$ 2,400	$ 2,400
Reliability	Electric Distribution Reliability	15	Overhead Protection	Cap	49	$ 6,204	$ 1,796	$ 3,100	$ 6,000	$ 6,000	$ 6,750
Reliability	Electric Distribution Reliability	15	Underground Protection	Cap	49	$ 2,298	$ 2,015	$ 1,600	$ 2,400	$ 2,400	$ 3,200
Reliability	Electric Distribution Reliability	15	Fault Indicators, Overhead and Underground	Cap	49	$ 2,944	$ 1,944	$ 2,500	$ 5,250	$ 5,462	$ 6,284
Reliability	Electric Distribution Reliability	15	Escalation	Cap	49			$ 1,719	$ 2,590	$ 2,459	$ 2,918

Except for the overhead conductor replacement program, the reliability initiatives were not classified as safety initiatives by Liberty or by PG&E. The Company observes a strong relationship between reliability and safety. Initiatives including PG&E's targeted circuit initiative (Exhibit (PG&E-4), Chapter 15, p. 15-21) and Fault Location, Isolation and Service Restoration (FLISR) projects (Exhibit (PG&E-4), Chapter 15, p. 15-20) seek primarily to improve reliability; however, they also provide safety benefits. PG&E proposes such projects primarily from a reliability perspective (which is how utilities undertaking similar activities generally justify



them); therefore Liberty does not treat them as system safety initiatives.

The CPUC released a Value of Service Study in May 2012. This study contains a system for ranking all reliability projects according to their improvement value to customers. This study was released too late for PG&E to use it in ranking items proposed in the GRC. PG&E did use the Value of Service ranking at the workpaper stage to validate its existing programs. This exercise showed the programs to be valid from the Value of Service perspective.

Liberty excluded reliability-targeted programs from the list of system-safety measures we examined. Improving a safety condition will very often benefit reliability. Reliability improvements will less often benefit safety. Outages that utilities, including PG&E, can avoid affect public or community safety (keeping people safe in general). These programs are classified as reliability programs. Safety programs focus on improvements targeted primarily to address system safety (correcting system conditions that cause hazards. The graphic above illustrates how safety and reliability programs further relate to each other.

b. Specific Initiatives

Substation Asset Strategy

Both Liberty and PG&E classified the items in Chapter 13 as Base Activities. PG&E is executing the base activity programs in a manner that makes no unaddressed safety risk apparent. Section C.4 notes that PG&E's forecast includes several substation transformer and switchgear replacement projects. While safety related, PG&E did not classify these expenditures in this response as addressing an identified risk. PG&E considers these projects as base-level activity, even though the absolute value of the expenditure forecast can vary from year to year depending on the complexity and timing of specific projects.

Liberty reviewed the substation distribution switchgear replacement program and the substation distribution breaker program. Certainly, failure to maintain or upgrade these breakers and switchgear could increase system safety risks. The PG&E asset management plan in place for these components mitigates risks. Liberty feels that the assets have been properly assessed and that a suitable strategic maintenance plan exists. The maintenance plan addresses both yearly maintenance and long-term replacement needs.

Overhead Conductor Replacement Program

The large amount of small obsolete conductors on PG&E's system reflects legacy conditions, which Section A.3 discusses. The issue rises to the level of serious safety concern. PG&E has 113,000 circuit miles of primary distribution conductor. Number 6 copper (#6 Cu) conductor comprises 22,206 miles (19.6 percent) of this total mileage. The industry formerly made widespread use of this #6 copper conductor, but now recognizes it as obsolete, due to its small size. The small conductor size makes it subject to greater breaking as it ages. Over many years of service, conductors will experience numerous situations of arcing together, due to high winds or lightning strikes. These occurrences cause small pits in the conductor. More robust larger conductor sizes better withstand this type of pitting without losing a material amount of strength.

Small copper wire also anneals at lower faults current levels than does larger conductor. Annealed copper becomes brittle and loses strength. Some utilities have safety rules precluding work on energized conductors this small, because of the high potential for breakage. In the past, PG&E conducted pull strength tests on #6 Cu conductors before scheduling replacement. The Company discontinued this after all of the conductors showed low strength. Past test results show conductors testing at around 65 percent of rated strength.

In addition to the #6 Cu, the PG&E system has 47,542 miles (41.9 percent of the 113,000 circuit miles of total primary conductor) of #4 ACSR conductors. The ACSR conductor has a steel reinforcement core. This type of conductor raises concerns due to its small size and to its bimetallic construction. The risk of bimetallic corrosion between the aluminum and the zinc on the steel core makes ACSR conductor not a good choice along coastal areas. Any deteriorated conductor section may be replaced under this program; however, the #6 Cu conductors are the primary concern. The analysis of 2010 outage data for conductor failure frequency shows one outage for every 102 miles of #4 ACSR conductors and one outage for every 59 miles of #6 Cu conductors. PG&E still purchases both the #6 Cu conductors and the #4 ACSR conductors.

A "wires-down" process, initiated in April 2012 consumes a minor portion of the costs of this program. PG&E implemented this forensic data-gathering process in conjunction with a Wire Down metric performance indicator. PG&E records the information gathered during the wire

down investigation process using Microsoft Excel. The program seeks to identify causes. The information gathered also includes conductor attributes (*e.g.*, size, type, span lengths, number of existing splices) and pole construction and site related data (*e.g.*, framing, corrosion area, snow area). PG&E also records potential corrective recommendations and other comments. The wire down investigation process currently excludes: (a) third party initiated events (*e.g.*, vehicle contact, gunshot, and metallic balloons), (b) events that occur during a classified Major Event Day as defined by the Institute of Electrical and Electronics Engineers (IEEE) standard 1366, and (c) older events not initially classified as a wire down event. All events initiated by vegetation contact are investigated by an employee of PG&E's Vegetation Management department. Based on Vegetation Management's recommendation, an engineer may also visit the site for a follow-up investigation.

The results of the wires down investigations indicated that a large percentage of downed conductors remained energized by the time that a PG&E Troubleman arrived on the scene. Ground fault currents occur when a conductor contacts a grounded object. A substation ground relay, a line fuse, or a recloser must sense the current, and clear the fault. PG&E observed that 38 percent of 12 kV system conductors were remaining energized. The corresponding 21 kV system percentage was 21. This hazardous situation combined with the propensity for the #6 Cu conductors to become annealed and break more readily.

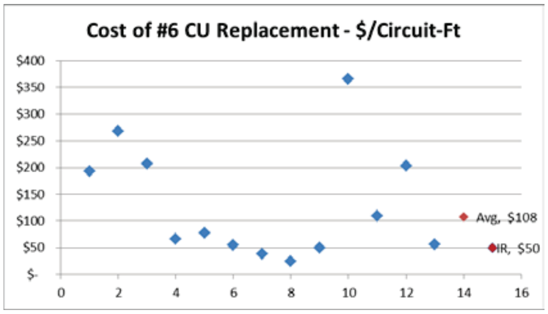
Liberty considers the percentage of downed energized conductors to be high. Benchmarking data is not readily available in the industry, but we have experience with some other utilities. We know of several major utility systems (23 kV) where downed energized conductors are estimated to be fractions of one percent. The main drivers for a high percentage of downed energized conductors could arise from a number of or a combination of factors (protection coordination practices, circuit grounding practices, transformer bank connections, and soil conditions among them). An outside consultant performed a distribution protection and coordination review for PG&E in 2012. The review verified that PG&E's protective coordination practices are superior and reflected what is currently considered good practice in the industry. PG&E is continuing to explore benchmarking data and circuit grounding practices, in order to obtain a better understanding of this issue.

PG&E determined the dollar amount of overhead conductor replacement work through the use of investment levels developed during the development of the overall system safety improvement plan. The Company used these forecasts, combined with historical costs from 2011 and 2012 overhead conductor replacement projects, to determine projected replacement amounts. PG&E uses a nominating process to identify the particular wire sections to be replaced in its planning processes. This process generates a list of projects. PG&E is developing tools to assist the planning areas with project identification. A software tool will use probability inputs (outage data, age, wire size, geography) and severity impacts (wire down history, number of customers, population density, wildfire risk) to rank the relative risk factor among their 155,000 protection zones. PG&E formerly called this tool the Risk Assessment Tool (RAT). It now uses the term System Tool for Asset Risk (STAR),

The GRC includes a plan to increase significantly the amount of overhead conductor being replaced from 2014 through 2016. PG&E proposed conductor replacement in the infrared inspections program (Chapter 5) and the overhead conductor replacement program (Chapter 15). The next table shows the total costs of these two programs and some associated data. In addition PG&E estimates that it will replace 250 miles of conductors in other programs, such as line capacity increases or new-business work.

Conductor Replacement Costs

Program Facet	Chapter 5 Conductor Replacement	Chapter 15 Conductor Replacement
Chapter Section	Electric Distribution Maintenance	Electric Distribution Reliability
2014 Forecast $ (000s)	$15,000	$32,500
2015 Forecast $ (000s)	$30,000	$34,130
2016 Forecast $ (000s)	$30,000	$34,509
Identification method	Infrared program	Planning area nomination process
Target conductor	Spans with three or more splices	Deteriorated or annealed conductor
Replacement method	Single span replacement	Multi-span replacement
Replacement $/Ft	$50	$108
Miles being replaced	113	62



We observed a cost per foot variance between the two programs. PG&E derived Exhibit 4 Chapter 15 costs by averaging the costs of various reconductoring projects. The scatter gram to the left shows the projects averaged. There is a wide variance in the costs per foot. The main factor in the variance was the size of the replacement conductor. Some of these projects involved replacements of a small conductor with a newer small conductor. Other projects involved betterment and upgrading to larger feeder conductor sizes. PG&E does not have a universally accepted replacement conductor in place for the #6 Cu or #4 ACSR conductors.

c. Justification

Again, we did not find risk assessments or cost/benefit analyses underlying the substation assets, planning & reliability initiatives addressed in GRC Exhibit 4 – Chapters 13 to 15. We did, however, find those programs to be contributors to mitigating safety risks, subject to several concerns.

We found the substation asset strategy programs to be effectively managed. Liberty believes that the assets have been properly assessed and that a strategic maintenance plan is in place. We observed no unaddressed safety risks.

We also found that the conductor replacement program addresses a serious safety issue. Its extent, however, is not reflected in this GRC. The impacts of conductor failures are magnified by the large percentage of downed energized conductors that remain energized. A recent fatality from these combinations occurred in 2012. This is a widespread safety concern which will take significantly more resources than those forecasted in this GRC to address.

We do not believe that Electric Operations has fully assessed the magnitude of the deteriorated conductor situation. The forecast levels for the Chapter 15 replacement did not grow from calculated needs based on a system assessment. Electric Operations has yet to fully assess the magnitude of the deteriorated conductor situation.

We found the unit costs of Chapter 15 conductor replacement to be high. The unit cost of replacement of $108 per circuit foot in Chapter 15 amounts to $570,000 per mile. Workpaper data indicates that replacement work can be done for around $50 per circuit foot, or $264,000 per mile. The main cost driver appears to be the lack of identification of a suitable replacement conductor. Many new aluminum alloy conductors (AAAC) now available have equivalent ampacity as the #6 Cu conductors and three to four times the breaking strength, and at an equivalent cost. Another factor in a high replacement cost is a lack of program controls. Rather than replace the conductors with equivalent ampacity wires, divisional engineers have installed upgraded feeder conductors, such as 4/0 aluminum. More effective program controls are in order.

PG&E's two different conductor replacement programs appear to compete with, rather than complement each other. Two reasonably aggressive programs are both "chasing the same prey." The Chapter 5 Maintenance conductor program looks for three splices in a span. These splices will generally only occur when the conductor has had past breaks. The Chapter 15 Reliability conductor replacement program is targeting conductors on the primary basis of outage history. This history also leads to conductors which have been often spliced. For small conductor replacement, it would be more appropriate to make the infrared and associated splice registry strictly an identification program rather than replacing conductor one span at a time.

9. Exhibit 4 – Chapter 16 – Underground Assets

a. Description

The next table lists the initiatives in this chapter and Liberty's classification of each initiative.

CRG Exhibit 4 Underground Assets Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Safety per PGE & Liberty	Underground Asset Managemer	16	Network Cable Replacement	Cap	56	$ 798	$ 7,000	$ 6,000	$ 21,000	$ 28,000	$ 28,000
Safety per PGE & Liberty	Underground Asset Managemer	16	TGRAM/TGRAL Switch Replacement	Cap	56	$ 20,881	$ 28,000	$ 22,400	$ 39,200	$ 39,200	$ 39,200
Safety per Liberty	Underground Asset Managemer	16	Tie-Cable Replacement	Cap	56	$ 1,814	$ 600	$ 200	$ 7,400	$ 6,800	$ 7,000
Reliability	Underground Asset Managemer	16	COE Cable Replacement	Cap	56	$ 15,647	$ 16,000	$ 16,000	$ 43,300	$ 41,200	$ 41,200
Reliability	Underground Asset Managemer	16	Reliability Related Cable Replacement	Cap	56	$ 16,681	$ 22,600	$ 20,600	$ 25,700	$ 26,300	$ 26,100
Reliability	Underground Asset Managemer	16	Escalation	Cap	56			$ 1,918	$ 3,478	$ 3,715	$ 4,293

b. Specific Initiatives

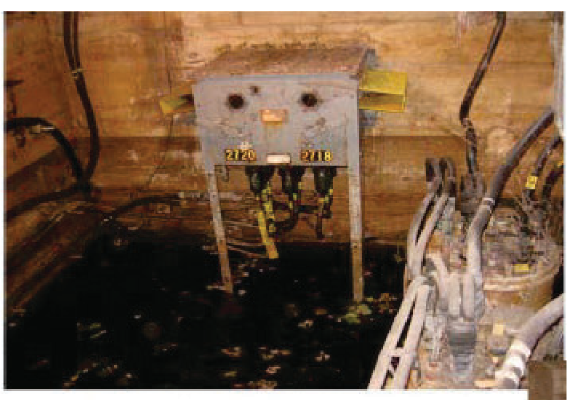
Network Cable Replacement

These primary voltage feeder cables and secondary cables lie within the San Francisco network. Twelve PG&E networks containing 69 primary feeders serving 1,366 transformers. PILC (Paper

Insulation/Lead Cover) comprises the bulk of the primary cable forecasted for replacement. These 1920 to 1960 vintage cables are reaching the end of their useful lives. Cable failures create risks of manhole explosion and fire when they fail. Manholes located below street grade often accumulate explosive gases (*e.g.*, gasoline vapors). Explosive gases in the manholes can ignite when cables fail. PG&E suffered fifteen failure incidents in 2011; three involved explosions and manhole cover displacement. The year 2012 witnessed 14 failure incidents; three involved explosions and manhole cover displacement. PG&E also experienced a 2005 electric-injury incident involving explosive manhole gases. These consistent failure incidents make addressing the risk an important safety initiative. The PG&E plan also forms part of a long range sustainability plan that has important reliability implications.

PG&E bases network feeder cable replacement prioritization on age, cable testing results, safety concerns, and circuit location. A VLF (very low frequency) cable insulation testing program exists. It is industry standard. PG&E's approach calls for replacing the entire feeder. A long-range asset management plan forecasts replacing all of the older PILC feeder cable by 2030. The Company forecasts eventual replacement of 60 of the 12 kV feeders. The current GRC replacement schedule includes 12 of these feeders. PG&E prioritizes the secondary cable replacements on the basis of their failure rate.

TGRAM/TGRAL Switch Replacement



The TGRAM/TGRAL (Transfer Ground Rocker Arm Main/ Transfer Ground Rocker Arm Line) switches represent an extremely antiquated type of underground oil switch. Vendors first introduced these switches in the 1920s. The design was obsolete by the 1960s. PG&E uses its TGRAM/TGRAL switches (1940s vintage) to sectionalize PILC cable. PG&E generally uses a three-way configuration, associated with a submersible transformer bank feed. The picture to the left shows a typical switch of this type. PG&E initially had approximately 1,000 such switches in service. The Company began a replacement project in 2009. Year end 2011 showed 616 switches remaining to be replaced.

PG&E has determined that these types of oil switches create inappropriate risk. Failure could occur during operation or maintenance, or in connection with the failure of nearby equipment. These oil switches have a history of comparatively high failure rates. The majority of these switches came from a single vendor. That vendor has issued several "Remove from Service" safety notices for these switches. The first service notice came on August 1, 1983. It recommended replacement with newer switches. A second, more strongly worded notice came on July 10, 1985. This notice cited switch failures involving "serious injuries and in some cases fatalities." A third notice came on March 21, 1997. This third vendor notice again "strongly recommend the de-energization and removal" of these switches. Approximately 500 of these switches remained in service on PG&E's system at the end of 2012.

PG&E has assessed the condition of these remaining switches, and has classified them into eight tiers. The GRC forecast includes removal of all remaining switches by the end of 2016.

Tie Cable Replacement

PG&E's tie cables serve as express bulk power 12 kV feeders. They run from one distribution substation containing a transformer bank to another distribution substation containing a set of switchgears for distribution to customer transformers. PG&E has used tie cable circuits in San Francisco and Oakland due to the limited number of transmission circuits in the area.

The PG&E proposal to replace this cable comprises a safety initiative; these cables are similar in nature to the network cables. These cables serve as parallel feeders. They release substantial fault energy in manholes when they fail. Like network cables, failures in tie cables can cause manhole cover displacements, and cause secondary gas explosions in the manholes.

PG&E forecasts the replacement of all PILC tie cables in East Bay by 2016. The cables being replaced have 1935 to 1948 vintages. These tie cable replacements represent the end of a decade-long plan to replace all tie cable circuits. PG&E started this replacement plan in 2003. The Company has replaced eleven circuits in San Francisco, with one project currently underway.

c. Justification

As is true for the other GRC Exhibit 4 initiatives, we found no structured risk assessment of cost/benefit analysis underlying the underground projects and programs addressed in Chapter 16. They do, however, contribute to mitigation of important safety risks.

We found that the network cable replacement initiative contributes to system safety by reducing the number of manhole explosions and fire risk. These cables are reaching the end of their useful lives. The cable failures create manhole explosion and fire risks when they fail.

We also found that the TGRAM/TGRAL switch replacement initiative contributes to employee safety by removing highly dangerous equipment. These switches comprise an antiquated type of underground oil switch. The switch vendor has issued several "Remove from Service" safety notices regarding them. The initiative will eliminate all of the switches by the end of 2016.

We also found that the tie cable replacement initiative contributes to system safety by reducing the number of manhole explosions and fire risk. Liberty considers this cable replacement to be a safety initiative because the cables are similar in nature to the network cables. Just like the network cables, the tie cable failures can cause manhole cover displacements and ignite secondary gas explosions in the manholes. These tie cable replacements represent the end of a decade long term plan to replace all of the tie cable circuits.

10. Exhibit 4 – Chapter 17 –Automation & System Protection

a. Description

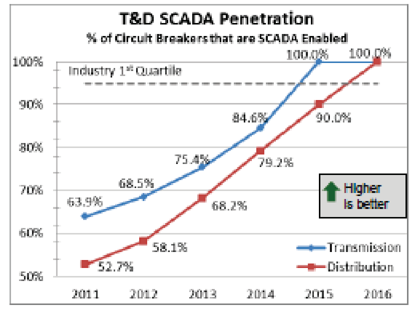
The next table lists the initiatives in this chapter and Liberty's classification of each.

CRG Exhibit 4 Automation and System Protection Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Dist Automation and System Prot	17	T&D System Automation	Exp	HX	$ 2,081	$ 3,189	$ 2,027	$ 2,027		
Base Activity	Dist Automation and System Prot	17	E Dist Automation and Protection	Cap	09	$ 745	$ 665	$ 3,623	$ 4,154	$ 4,085	$ 4,313
Safety per PGE & Liberty	Dist Automation and System Prot	17	Install Substation SCADA	Cap	09	$ 17,555	$ 29,942	$ 34,650	$ 58,300	$ 59,600	$ 59,600
Safety per PGE & Liberty	Dist Automation and System Prot	17	Replace Substation SCADA	Cap	09	$ 845	$ 3,278	$ 1,000	$ 2,000	$ 2,000	$ 2,000
Safety per PGE & Liberty	Dist Automation and System Prot	17	Install Feeder SCADA	Cap	09	$ 14	$ 1,000	$ 3,000	$ 5,000	$ 5,000	$ 5,000
Safety per PGE & Liberty	Dist Automation and System Prot	17	Replace feeder SCADA	Cap	09	$ 2,819	$ 1,100	$ 3,000	$ 2,000	$ 2,000	$ 2,000
Safety per PGE & Liberty	Dist Automation and System Prot	17	Fire Risk Management	Cap	09	$ 79	$ 1,200	$ 2,000	$ 2,000	$ 2,000	$ 1,000

b. Specific Initiatives

Substation SCADA



SCADA systems serve critical roles in monitoring and controlling widespread electric grids. They provide real time data and control functions for system operators. Substation SCADA systems for most major utilities are approaching 100 percent saturation. The application of SCADA at PG&E lags the industry considerably. See the accompanying graph. PG&E's saturation is at 58 percent, compared with an overall industry position of over 95 percent. This initiative will continue the SCADA additions underway and bring PG&E to 100 percent by 2016 (except for 4 kV substations).

Capital		Units			
MAT	Ops & Automation Description	2012	2013	2014	2015
09D	Dist Substation SCADA circuit breakers	168	151	265	278
67	Trans Substation SCADA circuit breakers	120	139	157	157

PG&E applies a prioritization system to set the order for SCADA installations. The prioritization model takes into account factors that include number of customers served, Urban/Suburban/Rural classification, Distribution Center Consolidation needs, and distributed generation installed.

SCADA installations provide a critical safety tool for mitigating the down-wire risk to which the PG&E system is particularly vulnerable. Downed electrical conductors remain energized 36 percent of the time (on the ground or on objects). Vehicle accidents have produced a number of occupant injuries and fatalities when exiting vehicles. First responders to the accident scene also face risks from conductors that have remained energized. The absence of SCADA inhibits line de-energization before Troublemen can arrive. Troubleman callout and arrival time can take up to an hour. SCADA control will allow the system operator to interact with 911 responders and to de-energize the line via remote control. Even de-energized down lines are not completely safe until grounding, but they are much safer than energized ones.

Feeder SCADA

Feeder SCADA consists of both new installations and replacements of older SCADA systems. PG&E is installing the new installations in locations where they can contribute to system safety (*e.g.*, urban and high pedestrian-traffic areas). The next table shows the numbers of installations included in the GRC forecast. PG&E's system employs about 6,000 reclosers.

GRC Forecast of SCADA Installations

Situation	2014	2015	2016
Installing radio communication to existing SCADA-ready devices	18	18	18
Upgrading existing controls to SCADA operability	170	170	170
New locations	50	50	50

PG&E has targeted another SCADA feeder initiative at replacing existing older SCADA controls. PG&E uses an older SCADA system, called PDAC (Primary Distribution Automation and Control). This system is over 25 years old. About 200 PG&E obsolete devices require replacement due to maintenance concerns. This initiative will replace about forty six devices per year, over a five-year duration.

The purpose of the SCADA feeder replacement subprogram is to perform lifecycle replacements of existing obsolete or unreliable feeder SCADA switches before they are rendered inoperable, thus posing potential safety or reliability risks. PG&E bases prioritization for selecting SCADA PDAC switch replacements on selection of the oldest vintage units, and prioritizing their replacement on the basis of criticality of the circuit. The Company's approach uses parameters such as the number of customers served and device performance. The objective of this subprogram is to replace feeder SCADA switches prior to failure.

Fire Risk Management

PG&E's Fire Risk Management (FRM) subprogram supports its public/system safety improvement initiative by reducing rural fire danger. Part of PG&E's efforts to improve system safety by reducing fire risk associated with its distribution system includes the addition of SCADA operability to existing line reclosers in the high fire risk areas by upgrading controls (where needed) and installing communications equipment. PG&E will then be able to change relay settings remotely during high risk times to non-automatic reclosing.

There are 615 reclosers in the high risk fire areas defined by the state. 375 reclosers are forecasted to be replaced in 2014-2016. Rather than use a scoring model, PG&E selected the device locations for SCADA installation under the FRM subprogram based on the California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) map zones (2010 Assessment). Deployments are occurring one division (geographic area) at a time to coincide with the rollout of the associated operating center control software.

c. Justification

As is true for the other GRC Exhibit 4 initiatives, we found no structured risk assessment of cost/benefit analysis underlying the automation and system protection work addressed in Chapter 17. The work, however, contributes to mitigation of important safety risks.

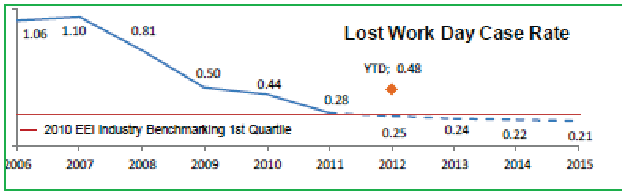
We found that the substation and feeder SCADA programs contribute to system safety by providing remote device-monitoring and operational capability. They are an important safety tool, providing remote monitoring and control capability. PG&E lags the industry considerably in the application of substation SCADA. This initiative will bring the substation SCADA capabilities at PG&E to industry levels by the end of 2016.

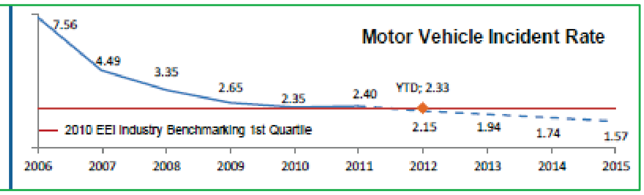
We also found that the Fire Risk Management SCADA program improves system safety by reducing the risk of wildfire ignition. The initiative provides SCADA monitoring and control for reclosers in the high risk fire areas. It contributes to system wildfire safety risk reduction by providing that monitoring and control.

F. Other Safety and Security Issues

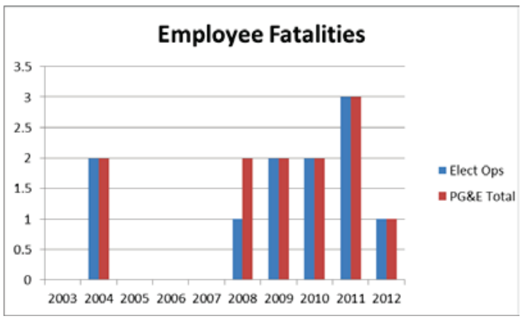
1. Employee Safety

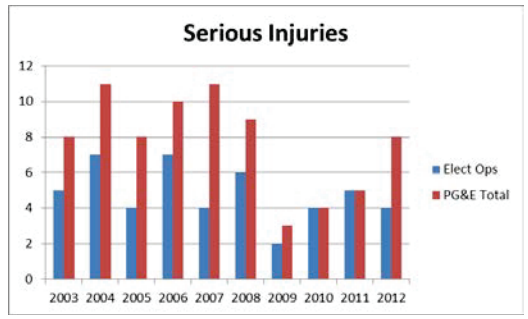
The graphs below show that Electric Operations has made progress in improving employee safety over the past six years. The final Lost Work Day Case Rate for 2012 was 0.38. The final Motor Vehicle Incident Rate was 2.059. These levels show substantial improvement over the 2006 levels.





Despite these positive trends, serious injuries and employee fatalities continue to be a problem requiring further mitigation.





In addition to employee fatalities and serious injuries, contractor fatalities and serious injuries are also a concern. Eight contractor incidents in 2012 resulted in a serious injury or fatality (four serious injuries; four fatalities). PG&E started formally recording and tracking contractor serious injuries and fatalities in 2012. Complete data is therefore not available for prior years.

PG&E realized some time ago that major and structural changes in the Electric Operations safety program were in order. The Electric Operations multi-year employee safety improvement plan focused on the following solutions and strategies:

- Create safety ownership at every level of the organization
    - Safety Management System
    - Safety Organizational Structure
- Shift the safety focus to recognizing and controlling exposure and risk
    - Hazard Identification and Risk Exposure Reduction
    - Near-Hit Reporting
- Enhance performance through training and development programs
    - Human Performance Tools
    - Critical Work Task Training

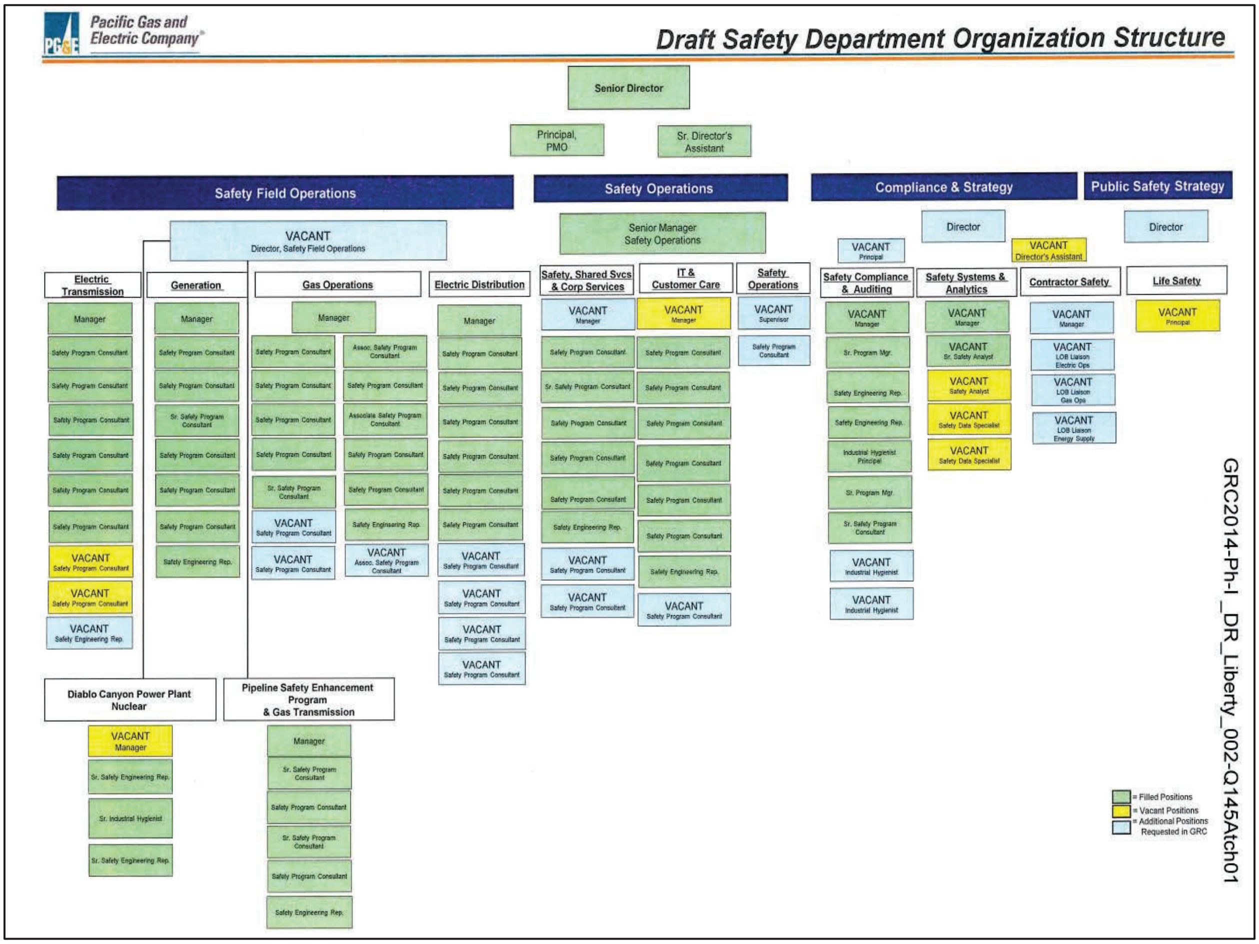
  - Hire-to-Retire Training Program
- Continuously improve by learning from industry best practices and internal safety audits and assessment

On November 3, 2011, the reorganization of Electric Operations resulted in the formation of a new safety team, (Electric Distribution Operations (EDO) Field Safety), dedicated specifically to helping improve organizational Safety and Human Performance. This team reports to the Executive VP – Electric Operations. The Field Safety Organization's primary goal has two fundamental components: (1) drive safe field practices and (2) assist in closing performance gaps. Approximately 2,200 field personnel form the focus of the EO Field Safety organization. Of this total, 1,800 work in Maintenance & Construction (M&C) and 400 work in in Restoration & Control (R&C).

Electric Operations Field Positions (Human Performance Specialist, Safety Program Specialist, and Safety Compliance Specialist) are titled differently from the corporate safety field positions. They are more methods and procedures oriented than are the corporate safety positions. Electric Operations has not yet completed the full staffing of these positions.

Grassroots Safety team participation in Electric Distribution Operations is also a focus area. Currently 233 field employees are on twenty six teams.

The Corporate Safety Department is also undergoing changes structured to address the safety performance. In 1997 PG&E decentralized the safety department. In 2005/2006 PG&E recentralized the safety department into the current group. The next diagram shows the draft Safety Department organization chart, reflecting a new organization structure. The chart identifies all filled positions (green), vacant positions (yellow), and new positions proposed in the GRC testimony (blue). The GRC forecast calls for adding twenty one employees to Corporate at an incremental cost of $3.6M.



Four new Safety Program Consultant positions are proposed for the Electric Distribution Field Operations group. Four positions are proposed for a new Contractor Safety group. The job responsibilities of the Safety Program Consultant positions are currently under review.

PG&E conducted benchmarking activities with Edison Electric Institute and the top seven utilities in safety performance. One recognized concern was the ratio of safety personnel to employees. The addition of the safety department personnel is directed at addressing this issue. Another issue is the amount of travel time for Electric Operations safety personnel due to the large service area. For example, between September 1, 2011, and February 29, 2012, the eight-person Electric Operations Field Safety team drove more than 235,000 miles – more than 4,900 miles (nearly 100 hours) per employee per month. Adding safety professionals means that time

spent on the road will instead be spent at work locations providing safety guidance, conducting hazard assessments or conducting incident investigations.

We found that current serious injury and fatality levels require significantly greater mitigation. PG&E had one employee fatality in 2012 due to a vehicle accident. There were four contractor fatalities (one of these being in Power Generation). Employee safety is recognized as a serious concern. The current levels of serious injury are intolerable.

We also found that the new Electric Operations Field Safety Team is better positioned to improve safety performance in Electric Operations. The concept of applying field safety personnel experienced in electrical distribution work methods and procedures is modeled after other utilities.

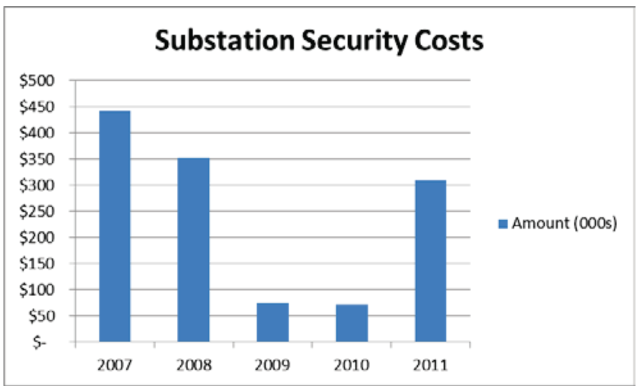
We also found that the addition of safety personnel is in line with other electric utilities and should contribute to improving field safety. The number of additional safety personnel being added will position PG&E in line with other utilities that are top performers in safety. This includes taking into account the numbers of safety personnel that were recently added from the new Electric Operations Field Safety organization.

2. Substation Security

PG&E has an operational risk titled *Electric substation physical reliability and security*. This was formerly an enterprise-level risk which was identified in 2010. The definition of the risk is, "*Criminal acts targeting PG&E that result in a risk to system safety, loss of life, catastrophic operational impact, or damage to the Company's reputation.*"

PG&E has issued mitigation plans since 2011. The risk assessment has determined that only transmission substations are at risk based on the definition. The transmission assets are not included in this GRC. PG&E did not deem distribution substations to be critical substations subject to targeted security risks. This determination is in line with industry and the 2012 National Research Council report on Terrorism and the Electric Power Delivery System. Distribution substations are targets of petty theft and vandalism, but not terrorist activity.

PG&E has an established distribution substation security program in place. This program addresses substation cyber assets, transmission substations and distribution substations. Distribution substations are divided into security classes. Managers can review the security classification of a substation and modify it as warranted by changing conditions at the substation. Corporate Security then applies security measures based on the classification of the substation. For distribution substations, security mitigation is an ongoing base activity with no apparent residual risk gaps. Exhibit 4 Chapter 13 contains $400,000 per year of expenditures for the installation of card readers at three San Francisco substations.



Distribution substation security incidents comprise an area where PG&E must maintain continued vigilance. The graph on the left shows the annual costs of all security incidents including, but not limited to theft, vandalism, etc.

Distribution substation security mitigation comprises a base activity; we observed no unaddressed risks. PG&E has a well-defined distribution substation security program in place. The program takes into account field needs and works closely with Corporate Security to put measures in place to meet those needs.

3. Public Outreach

From April 2004 to April 2012, almost 70 percent of all CPUC-reportable electrical contact incidents were from third party actions. It is by far the leading cause of reportable electrical contact incidents (see Section D.1). PG&E reported 73 individual incidents to the CPUC during that period. It is common in the industry for utilities to apply a robust public outreach program to help reduce third party electrical contacts.

Until early 2011, the Public Safety Section of the Safety Health & Claims department (now Safety Department) developed and implemented the Public Safety Information Program. The

program's goal was to increase awareness of the safe and proper use of gas and electricity by the public, customers and targeted third-party groups, and help reduce the risk of property loss, injury and death. A full-time PG&E employee in the Safety Health & Claims department managed the program. PG&E contracted out the design of public safety literature and resources. PG&E targeted elementary and middle school students, agricultural workers, contractors working around PG&E facilities, and first responders.

Utility	Residential Meters (MM)	Public Safety Budgets	$/Meter
2011 Proposed Budget	4.6	$ 723,390*	$ 0.16
PG&E 2010 Enhanced	4.6	$ 541,535	$ 0.12
PG&E 2010 Original	4.6	$ 385,286**	$ 0.08
PG&E 2006	4.6	$ 777,588	$ 0.17
Utility A	3.1	$ 369,000	$ 0.12
Utility B	3.9	$ 472,000	$ 0.12
Utility C	0.522	$ 131,000	$ 0.26

Budgets for these programs tended to peak in the 2006 period, and then fell until 2011. Beginning in 2012, PG&E expanded the public safety outreach programs and reorganized the management to include different departments.

The Public Awareness Program in Gas Operations funds and manages the Contractor/Excavator Program, Agricultural Worker Program, and School Outreach Program. The 2013 and 2013 budgets are shown in the table below.

Public Awareness Program Expenditures

Program	2012 Recorded	2013 Forecast
Contractor/Excavator Outreach Programs	$400,765	$401,771
Agricultural Worker Outreach Program	$86,100	$86,700
School Outreach Program	$346,320	$346,000
Totals	$833,185	$834,471

In addition to this activity, PG&E has the following outreach programs, which we address below.

Vegetation Management Public Education - Tree Worker Public Safety Outreach Program

The Tree Worker Outreach program is a part of PG&E's VM program and includes communication materials, outreach efforts, and tree planting events. The 2007 to 2011 recorded amounts averaged $327,600. The 2012-2014 forecasts for public education are $360,000, which is consistent with past years funding.

Electric Operations Emergency Preparedness & Public Partnership

Electric Operations' (EO) Emergency Preparedness & Public Partnerships (EP&PP) Team coordinates closely with the Gas Operations team and focuses its efforts on more complex electric-related events. The EO Public Partnership team is currently comprised of two Public Safety Specialists who report directly to the EO EP&PP Manager. The key focus areas for the team include: coordinated response to wild land fires; storm-preparedness and outreach; underground vault incident response; and electric substation response coordination.

For these key focus areas, the Public Safety Specialists deliver training to external first responders on PG&E's capabilities and response approach. During actual incidents, the Public Safety Specialists directly integrate with the external first responder Incident Commanders to share information in order to address public safety issues, including the protection of PG&E assets. The close coordination between PG&E, Cal Fire, and United States Forest Service (USFS) was noted extensively during multiple 2012 fires. The 2013 forecast for two full-time public safety specialists and the EO EP&PP Manager (40 percent allocated to PP) is approximately $340,000.

"Wires Down" Campaign

Electric Operations added a new public outreach program for general public awareness/safety in 2012. This program focuses on public awareness regarding downed power lines. The target audience is adults. The goal is to educate consumers on the danger of power lines and empower them to know what to do if they encounter a downed line. This is a four month campaign with a budget of $1.05 Million.

Community and Employee Engagement Team

The Community and Employee Engagement team manages the deployment of interactive gas and electric safety displays designed to educate customers, community members and children on safety awareness around PG&E's gas and electric facilities (See Exhibit PG&E-9, 9-11, This work began in 3Q of 2012 and will continue through 2013. The recorded costs for the safety board work in 2012 were approximately $650,000. The costs were split between Gas Operations, Customer Care and Electric Operations. The Community and Employee Engagement department consisted of twelve employees in 2011 (see WP 9-10, line 2, portion of total). In 2011, the total allocation was approximately 50 percent BTL (below the line). For 2014, PG&E forecasts it is going to do more work that is BTL and will increase its allocation to 80 percent BTL (see WP 9-31). PG&E does not expect staffing and funding levels to change in 2014.

Customer Care

Customer Care's Customer Education and Outreach efforts include the Electric and Gas Safety and Reliability Outreach initiative. This initiative aims to increase customer awareness and understanding of how to handle potentially hazardous situations involving electricity and gas. In addition, PG&E has found "electric safety board" public demonstrations to be effective in building awareness with customers in the case of a fallen power line and outage impacts.

PG&E plans to expand community-oriented and local outreach that will focus on general gas and electric safety awareness and education. PG&E plans to focus electric and gas safety and reliability outreach efforts in schools, community events and other customer interactions in the field in order to increase general understanding of electric and gas utility safety practices. The following electric and gas safety and reliability activities are proposed to improve safety and awareness: Local Events; Locally Targeted Media; Locally Targeted Outreach; Printed Collateral

and Online Communications; and Labor. The forecasted 2014 expense for these activities is $5.4 million, which includes content development and updates to educational materials and online content.

We found that, since 2010, PG&E has substantially increased public outreach programs to reduce electrical contact incidents. Third party actions are by far the leading cause of reportable electrical contact incidents. Overall PG&E has greatly increased their public outreach programs and focused on downed electric conductor safety. These programs are anticipated to contribute to reduced third part contact incidents.

4. Safety Performance Metrics

a. Employee Safety

Employee Safety Metrics

	Ref #	Metric — YTD Data through July 2012	YTD Actuals	YTD Target	YTD Amber Threshold	YTD Green Threshold	EOY Forecast	EOY Target	EOY Amber Threshold	EOY Green Threshold
Employee Safety	1	OSHA Recordable Rate[1]	2.485	Tracking Only			N/A	Tracking Only		
	3	Lost Work Day Case Rate [1,2]	0.477	0.249	0.261	0.249	N/A	0.249	0.261	0.249
	5	Motor Vehicle Incident Rate[1]	2.33	2.15	2.26	2.15	N/A	2.15	2.26	2.15
Public Safety	8	Wires Down	1,545	977	989	977	TBD	1,611	1,631	1,611
	9	Response to 911 Calls Within 60 Minutes	77.2%	70.2%	67.9%	70.2%	78.0%	70.0%	67.7%	70.0%
	10	Network System Failures	3	6	7	6	11	11	12	11
	11	Secondary Network System Failures	2	Tracking Only			Tracking			
	12	Incidents Resulting from Equipment Failures	1	0	1.17	0.58	1	0	2	1
	13	High Consequence EC Tag Completion	96%	100%	92%	96%	97%	100%	92%	96%

PG&E used industry-standard performance metrics for tracking employee safety (see table above). The definitions of these metrics are:

- <u>Lost Workday (LWD) Case Rate</u> – The number of LWD cases incurred per 200,000 hours worked, or for approximately every 100 employees.
- <u>Preventable Motor Vehicle Incident Rate</u> – The total number of motor vehicle incidents that the PG&E driver could have reasonably avoided, per one million miles driven. Starting in 2013, PG&E will replace the Preventable Motor Vehicle Incident Rate performance metric, with the Serious Motor Vehicle Incident Rate.
- <u>OSHA Recordable Rate</u> – PG&E has used the OSHA Recordable Rate as one of the key safety metrics for many years. In 2012, however, in an attempt to address the potential

risk of creating an incentive that could lead to under-reporting of employee injuries, they placed less emphasis on the OSHA Recordable Rate and removed the metric from their incentive targets. PG&E continues to track and report the rate, but did not establish performance targets. The rate calculation is the number of work-related injuries per 200,000 hours worked.

- Near Hits Reported – This is a new metric for 2012. Employees are encouraged to report near misses.

We found that the employee safety metrics area has been subjected to well-established, comparable measures between utilities and other companies. Traditional metrics for employee safety are the Lost Workday (LWD) Case Rate, Preventable Motor Vehicle Incident Rate, and OSHA Recordable Rate. The CPUC should continue to use these traditional metrics. They provide a consistent long term view and offer a comparable metric with other industries. The last three fatalities at PG&E have involved motor vehicle accidents. Once it has been established, the Serious Motor Vehicle Incident Rate could be added as a metric.

We also found the addition of a zero employee fatality goal to be appropriate. PG&E has occasionally experienced a year with zero fatalities. A zero employee fatality goal will be challenging due to the large size of the Company, but it should be considered. It is a common goal for many utilities. If the safety of employees, contractors and the public is to be improved, employees will need to lead the way.

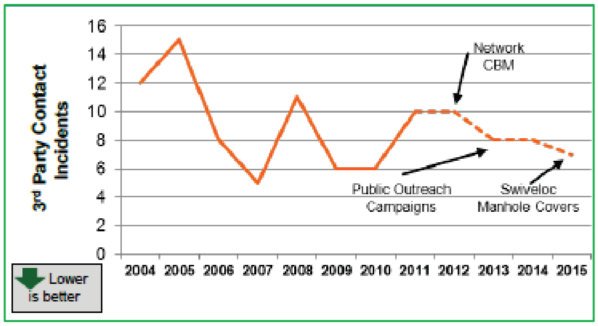
b. System Safety

The next table shows PG&E's current system safety metrics.

System Safety Metrics

2012 Metrics	Target	YTD (Nov)
Electrical Incidents resulting from equipment failure	0	1
Network system equipment and primary cable failures	11	9
T&D wires down (with exclusions)	2687	2673
911 emergency response - within one hour	77%	84%
High consequence EC tag completion timeliness	100%	99%

We found the T&D Wires Down (with exclusions) metric to be appropriate. The wires-down metric puts into play a number of issues at PG&E. Measurements are affected by the conductor replacement program, vegetation management program, pole replacement program, line inspection program and the infrared program. The metric is also important to system safety. It is broad-based and requires efforts in every division.



We also found the Electrical Incidents Resulting from Equipment Failure metric to be less meaningful than a Third Party Contacts Incident metric. The Electrical Incidents Resulting from Equipment Failure metric has a very narrow focus. Based on past history it will generally be either zero or one for the year. The Third Part Contacts metric includes electrical incidents from equipment failure. PG&E currently tracks this metric (see graph). This metric is impacted by programs such as equipment maintenance, line inspection and public outreach programs.

We also found that the *Network System Equipment and Primary Cable Failures* metric should be monitored for eventual removal. With forecasted network funding and improvements this metric will become less relevant each year. It is also a narrow metric from a corporate viewpoint since it is only in play in the bay area.

The bar can be raised for the *911 Emergency Response* metric. The bar is set low for this metric. It is currently easily being met.

A Replacement $/ft. Target for #6 Cu Conductor metric is appropriate. The magnitude of the small conductor replacement problem will require a well-managed long term effort. The unit cost of circuit replacement would be a good measure of the overall efficiency of the program. This metric would be impacted by actions such as conductor replacement program management controls, engineering and construction efficiency, and planning.

5. Root Cause Analysis

Root cause analysis is a problem solving tool that should form part of a risk assessment program. PG&E uses root cause analysis in several different situations.

Root cause analysis is a fundamental element in addressing employee safety. For every serious injury to an employee, PG&E's Serious Incident Analysis Resource Manual requires that an incident analysis team be formed and a root cause analysis be conducted. This action is a critical part of lessons learned evaluations and follow-up actions. This is a best safety practice.

Root cause analysis is not necessarily a fundamental part of public safety accident investigations. These incidents are generally investigated and controlled as Attorney-Client privilege. Admissions of error are not disclosed for legal reasons. Also, access to information from the injured party is not readily available. This is not to say that a corporation does not learn lessons or conduct follow-up due to public incidents. This is often done, but the follow-up is generally not formally associated with a particular incident.

There are several situations where root cause analysis is used to analyze distribution material failures. Due to the thousands of failures occurring each year, the normal outage report only contains an overall categorization of each failure. Only selected failures are examined in detail. The situations where a root cause analysis is conducted in Electric Operations are:

- Material Problem Reporting: Electric Operations has a Material Problem reporting procedure in place. Any field employee can request any specific material failure incident be investigated for root cause. It is standard in the industry to perform root cause material investigations on an as-needed basis.
- Wires down Investigations: Electric Operations has elected to perform a root cause investigation on every wire down situation in order to gather detailed failure data. This data will be used to inform and direct maintenance plans.
- Asset Maintenance Plans: Root cause analysis is often used as a part of data gathering to inform and prepare asset management plans. Electric Operations does not have a formal asset management system in place.

- Vegetation-caused Outages: Electric Operations investigates all vegetation-caused outages by an Arborist in order to determine the root cause.
- Risk Mitigation Plans: PG&E risk response plan templates include the analysis of risk drivers, which are root causes, as a part of the risk response plans.

We conclude that root cause analysis has been incorporated as an effective problem solving tool in electric Operations. As noted earlier, however, PG&E needs to assure that it populates data regarding system events robustly.

V. Other LOB Safety Projects and Programs

We also reviewed the projects and programs proposed by other LOBS to the extent that they involved safety or security initiatives.

A. Safety Department

PG&E's corporate Safety Department has responsibility for identifying, evaluating and controlling hazards, risks, and exposures to protect employees and the general public. The Safety Department has received considerably more emphasis in the past two years since the San Bruno incident. The Company established a lead safety officer position in 2011. The Safety Department establishes the overall framework for corporate-wide programs, and has developed and implemented new strategies and initiatives for the purpose of enhancing public and employee safety. Key components of the overall safety program include OSHA compliance, occupational injury and illness prevention, public safety, safety training, field safety observations, hazard and risk analysis, industrial and office ergonomics, motor vehicle safety, root cause incident investigations, and external benchmarking. The GRC includes several new safety initiatives that the Company believes will enable it to mitigate safety support gaps in field operations and that focus on incident prevention. The following table includes the new safety requests in the GRC forecast; all comprise expense items.

GRC New Safety Department Expenditure Requests

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Safety Department	Exh 7 Chap 2	Operational safety team labor escalation new hires	Exp	$ 127	$ 173	$ 178		
Safety Department	Exh 7 Chap 2	Operational safety increase 3 managers 8 safety consultants	Exp	$ 1,550	$ 1,550	$ 1,550		
Safety Department	Exh 7 Chap 2	Operational safety team 2014 10 additional staff	Exp			$ 1,335		
Safety Department	Exh 7 Chap 2	Safety Audit program	Exp			$ 225		
Safety Department	Exh 7 Chap 2	Contractor safety program	Exp			$ 150		
Safety Department	Exh 7 Chap 2	Pandemic Supplies	Exp			$ 275		
Safety Department	Exh 7 Chap 2	Migration of files	Exp			$ 250		

PG&E has requested 21 additional safety department employees in the GRC. The previous Director of Safety prepared the GRC safety initiatives and incremental expenses. A new director has come on board since then. The additional employees include three new managers for each of safety field operations, compliance and strategy and public safety strategy, and eight safety

program consultants, planned to be hired in 2012 at cost of about $1.55 million per year. The GRC forecast includes 10 additional safety staff, including safety engineers and the safety program consultants, planned for hiring in 2014, at a cost of approximately $1.34 million.

The approach of the new incumbent includes an increased focus on safety compliance and auditing, contractor safety, public safety, and field operations support. Implementation of this new strategy, as developed by the new director, will cause the changes shown in the organization chart from the preceding chapter.

The new senior director's approach does not require significant changes to what the GRC testimony already provides, according to the Company. The recently reorganized Safety Department continues to require approximately 21 additional positions. PG&E, however, has advanced the schedule for filling remaining positions from 2014 to the end of the second quarter 2013.

The GRC request also includes incremental expenses for public safety materials initiated in 2011, a safety audit program, a contractor safety program, pandemic supplies, and safety files migration. PG&E proposes to initiate in 2013 the activities that drive these incremental expenses, which the Company estimates at about $1.6 million per year.

PG&E has adopted the goal of reaching first quartile corporate safety performance. The Company is now determining what schedule to adopt for reaching this performance level. For the immediate term, a key safety goal for 2013 is to produce a 25 percent reduction in lost work days. That metric does have a target date (2015) for achieving first quartile performance.

A PG&E leadership safety assessment report in 2012 identified several gaps in the safety program. The Company has used this assessment, coupled with its benchmarking efforts, to address gaps in the safety program through new initiatives included in the GRC. These GRC initiatives do not find support from the new corporate risk assessment programs or cost-benefit analysis in the GRC, or in information that we learned during our review.

B. Corporate Real Estate

The next chart summarizes some of the changes that PG&E proposes with respect to real estate expenditures.

Real Estate Expenditures Identified by PSE&G as Safety Related

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Upgrade Program 12 buildings, reviews and upgrades	Cap	$ 1,769	$ -	$ 1,549	$ 401	$ -
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Program	Exp	$ 6,492	$ 3,912	$ 4,191	$ 4,300	$ 4,500
Corporate Real Estate	Exh 7 Chap 6	ADA program	Exp	$ 388	$ 484	$ 527	$ 527	$ 527
Corporate Real Estate	Exh 7 Chap 6	ADA assessments	Exp	$ 3,211	$ 3,307	$ 5,909	$ 5,909	$ 5,909

To assist in risk mitigation efforts, corporate real estate (CRE) has designated buildings that support activities critical to operations. These business-critical buildings include the Company's general office (which houses the San Francisco data center, gas control center, electric transmission operations center, and energy trading center), the Fairfield data center and security control center, and the Vacaville grid control center. CRE will improve the reliability of these buildings through seismic upgrades and maintenance to minimize the risk of interruption to these critical services. PG&E expects to complete structural seismic safety work at approximately 15 additional buildings by the end of 2016. CRE will also support reliability by creating a dedicated unit to operate and maintain these business critical operations.

PG&E's enhanced Americans with Disabilities Act (ADA) compliance program will improve safety for visitors and occupants of PG&E's facilities. With the assistance of external ADA experts, CRE will conduct ADA accessibility assessments at approximately 190 buildings to identify and implement accessibility improvements. The scope of the enhanced ADA compliance program goes beyond the scope of work and the surveys performed previously. Multiple access and egress routes in restrooms within the buildings that will be evaluated as part of the compliance program must be evaluated and upgraded as necessary because customers and the public meet with employees in interior offices and conference rooms.

The work associated with seismic issues represents a completion of work initiated some time ago and reviewed previously. We did not consider it a new initiative, and therefore did not review it. PG&E designated GRC expenditures associated with ADA as safety-related. When we interviewed Company representatives, the rationale for this designation was that, while the ADA

compliance activities in question here address access, such access must be provided in a safe manner. We did not find that explanation, however important ADA compliance is, to establish a safety nexus that is beyond what is normally expected for routine operations. We did not further examine the ADA expenditures.

C. Transportation Services

Transportation Services Expenditures Identified by PSE&G as Safety Related

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Transportation Services	Exh 7 Chap 3	Vehicle Safety & Opers Technology Projects	Exp			$ 1,000	$ 1,000	$ 1,000
Transportation Services	Exh 7 Chap 3	Incremental Vehicle Purchases	Cap			$ 52,000	$ 59,000	$ 46,000

PG&E has proposed the replacement of vehicles that have exceeded their lifecycle, or will exceed their lifecycle during the GRC period. The Company represents that this program is essential to maintaining a safe and reliable fleet that can reliably respond to operational issues. Transportation Services' vehicle replacement plan will enhance public and employee safety, maintain environmental compliance, and minimize vehicle downtime and repair costs. Achieving these objectives depends on replacing vehicles and equipment in a prudent fashion once assets have reached the end of their established life cycle. In light of the importance of the timely replacement of vehicles and equipment to the fundamental mission of Transportation Services, it has developed a five-year vehicle replacement plan designed to improve service quality and efficiency, and decrease the costs that are incurred through the retention of older assets. In 2014, 70 percent of the transportation services capital budget forecast is to comply with the negotiated California Air Resources Board alternative compliance plan.

The safety nexus PG&E asserts for this program is that, while obsolescence is the basis for proposed vehicle replacements, safety is implicated because using older vehicles is not as safe. We did not find that explanation sufficient to make vehicle replacement a safety versus an efficiency and environmental compliance based decision. We did not review this program.

PG&E has developed a safety initiative in which transportation services will implement onboard fleet telematics designed to reduce the risk of accidents, thereby increasing driver safety. This

initiative includes associated back-end systems needed to track and store the data produced by this technology. A telematics system will allow transportation services to track driving patterns, including: speed, lane departure, collision avoidance, and monitor driver reaction. The system includes backing technology and dashboard cameras for 900 vehicles in phase 1 and 1,800 vehicles over the three-year GRC cycle.

D. Corporate Security

GRC Corporate Security Initiatives

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Corporate Security	Exp 9 Chap 3	Corporate Security New Employees	Exp	$ 223	$ 514	$ 981	$ 1,010	$ 1,041
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Exp			$ 1,000		
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Cap			$ 500	$ 650	$ 700
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Exp			$ 470		
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Cap			$ 1,720	$ 1,920	$ 1,520
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Exp			$ 200		
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Cap			$ 500	$ 500	$ -
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Exp			$ 375		
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Cap			$ 150		

PG&E Corporate Security has responsibility for security in facilities across the Company footprint. Corporate Security plans made part of the GRC include an increase in staffing and four information technology projects designed to replace certain assets and to enhance physical security programs.

PG&E plans to add four new physical security specialists to assess existing security measures and to identify additional measures needed to prevent criminal activity at the Company's approximately 5,000 facilities. This request includes a security director with expertise and knowledge in physical security mitigation strategies, cyber security vulnerabilities and risk modeling and intelligence gathering to support the use of technology and data analytics in security. The current security director will retire within one year; the Company is bringing in his replacement in advance and will provide for training and transition.

One of the new physical security employees will manage the life safety program. The department now employs a life safety program manager for safety, security and real estate at the headquarters building. The new employee will have responsibility for all other facilities, to

assure robust and coordinated attention to these areas company-wide. The GRC includes the addition of two full-time and one part-time physical security specialists to heighten physical security programs and combat criminal activity targeting PG&E assets, and to provide for increased employee and public security at facilities. PG&E explains that corporate security needs have expanded greatly over the years since 9/11. For instance, FERC hydro-security regulations have increased, and new TSA guidelines were issued in 2007. Enhanced levels of security using updated technology have become both required and desired. During the past five years, PG&E has greatly expanded its security philosophy and its workload. Numerous new security initiatives are already in place, and the Company needs additional staff to catch up with the previously expanded work load.

Two additional employees in the business continuity and emergency management area will be added to perform business continuity planning and standards certification consistent with Department of Homeland Security requirements. A second employee will perform business impact analysis at the Company (last performed in 2010 and 2011). More frequent business impact analysis is driven by an increasing dependence on technology and by changes in the IT sector. The Company notes the business impact analysis is also required for effective disaster recovery planning.

The next table shows the GRC cost of the 6.3 additional full-time-equivalent employees. PG&E added the 2.3 physical security specialists in 2012, with the security director planned for 2013, and two new business continuity specialists and the life safety specialist in 2014.

PG&E did not use formal risk assessments to justify the additional staffing requests and we have not found specific cost-benefit analysis to underlie them.

Corporate security also requested four IT programs in the GRC: the security management system implementation, corporate security asset management, physical security incident management and business continuity communication projects. The first project addresses replacement of over 60 outdated employee access card systems to improve facility security, and includes servers, software training and licensing with a three-year rollout period. The security asset management

investments comprise replacements of security assets that include video cameras and alarm controls that are up to 20 years old. The investments also will upgrade asset databases. The program includes a $5 million investment in assets over the three-year rollout period, as well as training, maintenance and license expenses in 2014. The incident management program will provide a software platform that enables the security system to operate effectively. PG&E proposes to implement it in 2014 and 2015. Company management notes that its security equipment is dated, and that PG&E fell behind in replacing the equipment over the past 10 years. Replacement on a five-year cycle is desired for security equipment, and the Company believes that it needs to make these investments over a three-year period to get near such a cycle.

The Company also includes initiating an emergency management notification system to automate manual systems, plan activities resulting from a catastrophic incident, and allow company-wide communications after such an incident. PG&E conducted a pilot initiative under baseline funding in 2011, finding that it demonstrated the viability of such a system for use in emergency response. The table above shows the capital investment and operating expense related to these security-related initiatives. PG&E included written justification of each these projects in its GRC work papers, but has not performed formal risk assessments, or provided specific cost-benefit analyses to justify them.

E. Risk and Audit

GRC Risk and Audit Initiatives

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Risk and Audit	Exh 9 Chap 3	Enterprise Risk Management 3 new employees	Exp	$ 540	$ 556	$ 573		
Risk and Audit	Exhibit 9 Chap 3	Enterprise Risk Management consulting	Exp			$ 50	$ 50	$ 50
Risk and Audit	Exh 9 Chap 3	Alternate Emergency Operations Center	Cap			$ 19,900		

The GRC request for the risk and audit organization includes two substantial capital projects: the Alternate Emergency Operations Center (AEOC) and the alternate Company headquarters (AC HQ). Together they involve a capital investment of almost $20 million.

PG&E currently maintains a full emergency operations center adjacent to its headquarters site in downtown San Francisco. The Company also has both an alternate headquarters and an alternate

emergency operations center at another location. However, both locations lie within the Hayward primary earthquake zone, which could render both partially or totally unusable in a major seismic event. The US Geological Survey estimates that this area faces a 63 percent probability of a 6.7 or greater earthquake over a 30-year period. PG&E's emergency plan and business continuity plans call for an alternative headquarters site and an alternative emergency operations center outside major earthquake zones. The Company notes that no specific site has been picked for these backup facilities. This particular risk was one of the top 10 risks identified in the enterprise risk management program, which included a mitigation plan for the risk and estimated funding requirements.

As noted in the table above, PG&E's estimated construction costs are $13 million, and IT costs are $6.9 million for the two facilities. The GRC work papers noted that, "The project will improve the likelihood that PG&E will be able to restore essential emergency command and service restoration in a timely fashion following an event that renders the facilities in San Francisco and San Ramon inoperable." PG&E did not prepare a quantified assessment of event probability times the event consequences for comparison to expected facility costs. This GRC request was not founded on a formal risk assessment and PG&E has provided no cost-benefit analysis.

As noted elsewhere in this report, the corporate risk management organization is taking an expanded role in managing risk at PG&E, including establishing and managing a operational risk management program. Due to its expanded role, the risk management team will add three additional staff, including a manager, an additional principal and a business analyst. Previously, the risk management team had two principals. The three additional employees were to be hired in 2012 with a burdened cost of about $540,000 annually, as noted in the table above. Additional consulting expense related to risk management activities of $50,000 per year is also included.

F. Human Resources

The Company believes that a key to providing increased levels of safety and reliability set forth by the LOBs is the ability to attract and hire qualified employees. The HR department is forecasting an increase in the number of recruiters, continuation of the work force development

programs, and technology enhancements so that PG&E can attract, select and hire skilled and qualified workers required to deliver safe and reliable service to customers. With a significant number of employees expected to retire from PG&E in the coming decade, the human resources organization must be proactive in developing sourcing strategies and partner with organizations that can work with PG&E to build the skills of prospective employees.

Human resources will develop and deliver training for new and long tenured employees so that they have the knowledge and skills necessary to safely and correctly perform their assigned work. The GRC forecast includes an increase in funding for PG&E Academy to provide instructional design, oversight of curriculum development, and resources to support the ongoing maintenance of training that is developed so that employees are trained to perform work according to the most current regulations, follow correct procedures and given the know-how to use required equipment.

We view the need for attracting and hiring qualified employees as serving a broad set of purposes. We did not find these efforts to have a sufficient safety nexus to call for our examining them.

G. Justification for Shared Services and A&G GRC Initiatives

The Shared Services and Administrative and General support organizations' safety and security spending in GRC forecasts were generally justified by written arguments, and not by risk assessments or cost/benefit analysis.

The GRC includes several new corporate safety initiatives from the Shared Services Safety Department that PG&E believes will enable it to mitigate safety support gaps in field operations and new safety initiatives that address incident prevention. The Company has requested 21 additional safety department employees in the GRC, including three new managers, for a 2014 cost of about $3.1 million. The GRC request also includes incremental expenses for public safety materials that were initiated in 2011, and for a safety audit program, a contractor safety program, pandemic supplies and safety files migration, all to be initiated in 2013. The total annual expense for these new programs is estimated at about $1.6 million per year. PG&E's leadership safety

assessment report from 2012, coupled with benchmarking efforts, addressed gaps in the safety program through new initiatives that are included in the GRC.

PG&E corporate security is a central services organization in the Administrative & General LOB that is responsible for security in numerous facilities across the Company. Corporate security plans to increase its staff by 6.3 employees, including a new security director, at a 2014 cost of about $1 million. Corporate security is also planning for four information technology projects to make asset replacements and enhancements to the PG&E's physical security programs. The security assets and programs includes an $8 million investment in assets over a three-year rollout period from 2014 to 2016, as well as training, maintenance and license expenses of $2 million in 2014.

During the past five years, PG&E has greatly expanded its security philosophy and its workload. Numerous new security initiatives are already in place, and the Company represents that it needs additional staff to catch up with the previously expanded work load. Company management also reports that its security equipment and assets are quite dated, and that the Company fell behind in replacing security equipment over the past 10 years. Replacement on a five-year cycle is desired for security equipment, and the PG&E believes that it needs to make these investments over a three-year period to get near such a cycle.

The $20 million GRC request for the AEOC and the ACHQ included work papers noting that, "The project will improve the likelihood that PG&E will be able to restore essential emergency command and service restoration in a timely fashion following an event that renders the facilities in San Francisco and San Ramon in operable." A quantification of event probability times the event consequences as compared to cost were not prepared for the GRC justification in the work papers, and no specific cost-benefit analysis was performed.

The risk management team will also add three additional staff with a cost of about $540,000 annually; PG&E included written justification of each these projects in its GRC work papers.

The Company included written justification of each these projects in its GRC work papers; formal risk assessments or specific cost-benefit analyses were not used to justify these projects.

The following table identifies those initiatives and expenditures identified in the 2014 GRC as safety-related. Liberty has addressed each area identified in the table in the discussion above, with the exception of customer care initiatives. We did not find these efforts to have a sufficient nexus to electricity distribution or power generation.

Summary of Shared Services and A&G GRC Initiatives

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Customer Care	**Exh 5**							
Customer Energy Solutions	Exh 5 Chap 7	Elec and Gas Safety Outreach new program	Exp			$ 5,433		
Contact Center Operations	Exh 5 Chap 2	Customer Service Rep Training	Exp	$ 1,502	$ 1,542	$ 1,586		
Customer Advocacy Team	Exh 5 Chap 2	19 new CSRs and 1 supervisor	Exp	$ 1,677	$ 1,723	$ 1,770		
Customer Inquiry	Exh 5 Chap 2	Expand Sacramento and Fresno Contact Centers 135 seatsE	Cap			$ 15,495		
Office Services	Exh 5 Chap 3	Ergonometric Work Stations	Exp			$ 1,039	$ 1,134	$ 1,158
Office Services	Exh 5 Chap 3	Ergonometric Work Stations	Cap			$ 2,424	$ 2,646	$ 2,703
Revenue Assurance	Exh 5 Chap 4	13 New Field Reps	Exp			$ 1,300		
Metering	Exh 5 Chap 5	18 New Management Personnel	Exp			$ 2,075		
Metering	Exh 5 Chap 5	18 New Management Personnel	Cap			$ 818		
Shared Services								
Safety Department	Exh 7 Chap 2	Operational safety team 2011 public safety materials	Exp	$ 700	$ 700	$ 700		
Safety Department	Exh 7 Chap 2	Operational safety team labor escalation new hires	Exp	$ 127	$ 173	$ 178		
Safety Department	Exh 7 Chap 2	Operational safety increase 3 managers 8 safety consultants	Exp	$ 1,550	$ 1,550	$ 1,550		
Safety Department	Exh 7 Chap 2	Operational safety 2011 safety assessments one-time	Exp	$ -	$ -	$ -		
Safety Department	Exh 7 Chap 2	Operational safety team 2014 10 additional staff	Exp			$ 1,335		
Safety Department	Exh 7 Chap 2	Safety Audit program	Exp			$ 225		
Safety Department	Exh 7 Chap 2	Contractor safety program	Exp			$ 150		
Safety Department	Exh 7 Chap 2	Pandemic Supplies	Exp			$ 275		
Safety Department	Exh 7 Chap 2	Migration of files	Exp			$ 250		
Transportation Services	Exh 7 Chap 3	Vehicle Safety & Opers Technology Projects	Exp			$ 1,000	$ 1,000	$ 1,000
Transportation Services	Exh 7 Chap 3	Incremental Vehicle Purchases	Cap			$ 52,000	$ 59,000	$ 46,000
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Upgrade Program 12 buildings, reviews an	Cap	$ 1,769	$ -	$ 1,549	$ 401	$ -
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Program	Exp	$ 6,492	$ 3,912	$ 4,191	$ 4,300	$ 4,500
Corporate Real Estate	Exh 7 Chap 6	ADA program	Exp	$ 388	$ 484	$ 527	$ 527	$ 527
Corporate Real Estate	Exh 7 Chap 6	ADA assessments	Exp	$ 3,211	$ 3,307	$ 5,909	$ 5,909	$ 5,909
IT	Exh 7 Chap 8	Disaster Recovery Program	Exp			$ 3,100	$ 3,100	$ 3,100
IT	Exh 7 Chap 8	Disaster Recovery Program	Cap			$ 33,900	$ 44,000	$ 18,700
Admin and General								
Risk and Audit	Exh 9 Chap 3	Enterprise Risk Management 3 new employees	Exp	$ 540	$ 556	$ 573		
Risk and Audit	Exhibit 9 Chap 3	Enterprise Risk Management consulting	Exp			$ 50	$ 50	$ 50
Risk and Audit	Exh 9 Chap 3	Alternate Emergency Operations Center	Cap			$ 19,900		
Corporate Security	Exp 9 Chap 3	Corporate Security New Employees	Exp	$ 223	$ 514	$ 981	$ 1,010	$ 1,041
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Exp			$ 1,000		
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Cap			$ 500	$ 650	$ 700
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Exp			$ 470		
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Cap			$ 1,720	$ 1,920	$ 1,520
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Exp			$ 200		
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Cap			$ 500	$ 500	$ -
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Exp			$ 375		
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Cap			$ 150		
Human Resources	Exh 8 Chap 4	E recruit project	Exp	$ 557		$ 240	$ 150	
Human Resources	Exh 8 Chap 4	E recruit project	Cap	$ 3,200		$ 1,200	$ 750	
		Support Services Safety/Security Capital		***$ 4,969***	***$ -***	***$ 130,531***	***$ 109,867***	***$ 69,623***
		Support Services Safety/Security Expenses		***$ 16,967***	***$ 14,461***	***$ 36,457***	***$ 17,680***	***$ 17,285***

Appendix A -- Evaluation Criteria

CORPORATE SAFETY & SECURITY RISK MANAGEMENT

1. The overarching framework for identifying safety and security related projects and programs should be clear, comprehensive, and appropriate.
2. Asset management strategic programs should incorporate risk management plans and procedures.
3. The process for prioritizing safety and security projects and programs vis-à-vis each other and with respect to meeting other objectives (e.g., reliability, environmental compliance, customer satisfaction) should be rational, comprehensive, and consistently applied.
4. The Company should have adopted and it should operate under duly emphasized corporate leadership and a program for broad and complete assessments and management of the safety and security risks that affect its operations.
5. The program for assessing risk should be actively overseen by the most senior levels of company management and direction.
6. There should be complete, comprehensive documentation of risk assessment goals, policies, procedures, controls, and metrics.
7. Risk assessment and management should be supported by adequate resources under a disciplined approach informed by current industry thinking and approaches.
8. PG&E's methods for performing and using risk assessments should be informed by a structured, comprehensive process for identifying best industry practices.

LOB-LEVEL SAFETY & SECURITY RISK MANAGEMENT

9. The Company should perform and maintain a current, comprehensive assessment of the system's physical condition; this assessment should rely upon comprehensive efforts to gather and assess system data and to assess causes of recurring problems.
10. Risk management should be incorporated into the planning and execution of LOBs at the operating level.
11. LOB activities should be supported by trained risk assessment resources and conducted under structured and comprehensive goals, policies, procedures, controls, and metrics.
12. The bottoms-up risk assessment of the LOBs should inform risk management activities at the corporate or enterprise level.

13. There should be a structured, evidence-based process for identifying improvement opportunities and for selecting from among them.
14. There should be a structured process for analyzing asset performance and performing condition assessment.
15. There should be a register of key assets supported by risk profiles.
16. Risk assessments should apply sound, accepted concepts and techniques supported by the appropriate levels of technical and operational expertise.
17. PG&E should execute and rely on current assessments of the probability and consequences of safety and security failures for customers, the public, and employees.
18. Assessments of safety and security risks should produce well-founded assessments of risk probability, consequence, mitigation measures, the costs of available mitigation measures, and the difference in risk probability or consequence produced by each such measure.
19. The selection of programs, projects, and other sources of expenditure should result from a careful consideration of a set of robust, fully considered alternatives.
20. The data used to identify and select from among alternatives should be clear, complete, and accurate.
21. The risk reducing characteristics of proposed programs, projects, and other sources of expenditure should be clear, convincing, and quantified to the extent practicable.
22. The degree to which further risk mitigation activities would produce incremental improvements and at what cost should be considered and should be retrievable.
23. Planned projects and programs should be fully reflective of and responsive to the results of CPSD inspections and audits.
24. Supporting systems and procedures should facilitate the execution and management of risk management plans.

SAFETY and RISK IN OPERATIONS PLANNING

25. Top down financial objectives that lead operations planning and budgeting activities should not foreclose full and careful consideration of risks as part of the planning and budgeting processes.
26. Operations planning should incorporate comprehensive risk assessments and analyses routinely and in advance of plan and budget formulation.

27. The projects and programs proposed should reflect and conform to the results of risk assessment processes; the linkage should be clear.
28. How assessments of safety and security risks are considered among other planning factors (e.g., service reliability and quality, customer satisfaction, environmental stewardship) should be clear.
29. It should be clear that the balancing of safety and security risks with other planning factors takes due account of rate and financial consequences, both short and long term.

RISK/REVENUE REQUIREMENT NEXUS

30. Rate filings should reflect an enhanced and specific approach to risk assessment.
31. The Company should provide sufficient explanation of risk-based plans and identify revenue requirements impacts to permit stakeholders and the Commission to make informed value judgments about them.
32. The Company should recognize and respond to the need for soundly connecting risk analysis and proposed expenditures.
33. The Company should have clear, executable, and appropriate plans for progressing toward a state that will conform its risk management processes to an industry leading position, particularly with respect to gauging the revenue requirements impacts of discrete projects and programs to address safety and security risks.
34. The current rate filing should permit the identification of projects and programs explicitly associated with discrete safety and security risks.
35. The Company should be able to demonstrate that the projects and programs proposed in the rate case to address safety and security risks represent optimum risk mitigation alternatives.
36. The Company should be able to demonstrate that its balance of expenditures proposed in the current filing has taken due account of all risks and needs (not just safety and security) with due consideration for overall rate impacts to customers.
37. The level of funding for safety projects and programs should be commensurate with appropriately and fully identified and assessed safety risks.
38. Proposed LOB and total safety expenditure levels should be commensurate with appropriately identified and assessed safety risks.

EXHIBIT D

IN THE SUPERIOR COURT OF THE STATE OF CALIFORNIA

IN AND FOR THE COUNTY OF BUTTE

IN RE:	)	
	)	
CONFIDENTIAL GRAND JURY PROCEEDINGS	)	BCSC-2019-GJ-001
	)	
	)	
	)	
	)	
	)	

CERTIFIED COPY

REDACTED CONFIDENTIAL GRAND JURY PROCEEDINGS

TUESDAY, FEBRUARY 25, 2020

VOLUME 41

OROVILLE, BUTTE COUNTY, CALIFORNIA

ASHLEIGH BUTTON, CSR NO. 14013, OFFICIAL COURT REPORTER

SEALED PURSUANT TO PENAL CODE 938.1(b)

APPEARANCES:

FOR THE BUTTE COUNTY DISTRICT ATTORNEY'S OFFICE:

Marc Noel, Deputy District Attorney
Jennifer Dupre-Tokos, Deputy District Attorney
25 County Center Drive, Suite 245
Oroville, California 95965

--o0o--

I N D E X

THE WITNESS: Electric asset management is subordinate to electric operations. Electric operations is defined as the senior vice president level.

Electric asset management starts at the vice president level.

MR. NOEL: Did you ever in your position as senior director of transmission asset management directly or indirectly inform those management levels to whom you reported of the prominent enterprise risks of wildfire and their apparent relationship to deteriorated and dilapidated infrastructure?

THE WITNESS: Yes.

MR. NOEL: And do you recall to whom you reported that?

THE WITNESS: I was a part of our risk management processes and had the opportunity to communicate the risk and associated mitigations to many of our senior officers through our integrated planning processes.

MR. NOEL: And which senior officers?

THE WITNESS: I don't recall all of the names.

MR. NOEL: Would one of them have been your direct supervisor, Kevin Dasso?

THE WITNESS: Yes.

MR. NOEL: And would another have been Mr. Dasso's direct supervisor Patrick Hogan?

THE WITNESS: Yes.

MR. NOEL: And would it also include the president Geisha Williams?

THE WITNESS: Yes.

MR. NOEL: Do you recall what you told the senior officers about the wildfire risk and the relationship with deteriorated, dilapidated infrastructure?

THE WITNESS: Specifically, no. Generally, the information that I would have communicated would be consistent with our 2017 RAMP filing.

MR. NOEL: And do you remember when these briefings occurred?

THE WITNESS: I do not.

MR. NOEL: Were you ever involved in any capacity in PG&E deliberations regarding infrastructure project proposals for replacing deteriorated and/or dilapidated infrastructure that resulted in such project proposals being canceled or not approved?

THE WITNESS: I don't believe so.

MR. NOEL: Does population density have anything to do with the attention given to specific towers?

THE WITNESS: Yes.

MR. NOEL: Why is there specialized attention given to towers in corrosion zones but no specialized attention given to towers in high wind mountain areas?

THE WITNESS: So I can't categorically say that special attention isn't provided to facilities in zones

susceptible to higher winds. We actually design to a higher standard for facilities that are sited in high wind areas. In terms of corrective actions, I would say that my belief is that our industry, as well as PG&E in my organization, are better informed in the impacts and the visible degradation associated with corrosion. I believe that our industry is not as mature in terms of understanding the short and long term implications of wind exposure.

MR. NOEL: Part of your job is to identify work for six years out, why was there never any work scheduled for assets approaching 100 years -- 100 years old as a deteriorating asset?

THE WITNESS: Is that in reference to Caribou-Palermo?

MR. NOEL: Yes. And, obviously, she put in the caveat "other than mandated work such as the NERC projects"?

THE WITNESS: Understood. Specific to Caribou -- Palermo, as I alluded to previously, we had in-flight in our portfolio, the NERC alert projects from the Caribou-Big Bend to Caribou-Palermo. Those projects were originally scoped and initiated to comply with the NERC alert in 2010.

Through the process of detailed engineering, the project team did identify opportunity to potentially

expand scope, opportunity wasn't under evaluation. As a result, the timeline for gate to authorization was actually pushed out to do further assessment; unfortunately, the line itself was put on a permanent outage and retired in place prior to proceeding with those activities. So too late for that work to be complete prior to 2018.

MR. NOEL: Where would we find documents pertaining to this proposed work that was going to be added to the NERC projects?

THE WITNESS: I'm not sure.

MR. NOEL: As a senior director, upper-management involved in assessing information from the field -- qualified-field experts, is one of the factors to determining your risk to asset -- okay. Let me reread that. I think I screwed it up.

As a senior director involved in assessing information from the field, is one of the only factors to determining your risk to assets -- I'm still having trouble with it.

Are there processes in place to mitigate having no data, falsified data or incomplete data from the field?

THE WITNESS: So as I previously noted, there are processes in place to leverage existing data to supplement missing data. Proxy data can be applicable in many instances.

If data is missing or found insufficient, there was no alternate data available to leverage in its place, then we would initiate a field engagement in order to collect additional information.

MR. NOEL: Have you or members of your team to your knowledge authorized notification extensions that you personally were informed about or were notified through documents? So in other words, an LC notification has been created, it sets a timeframe for when the work needs to be done, have you personally ever done extensions on those notifications or reviewed extensions done by people on your team?

THE WITNESS: In my position, I was not a part of the extension process for the LC notifications. So I have not been a part of that approval process.

MR. NOEL: Finally, we've heard testimony about a compensation formula for bonuses. Would you please explain your compensation formula for bonuses?

THE WITNESS: Can you tell me what point in time?

MR. NOEL: When you were the transmission asset management, the senior director, prior to the Camp fire.

THE WITNESS: So in general, bonuses are structured to -- to be set on a target percentage depending on position. For example, 15 percent of base salary would be the target bonus. Those target values are then multiplied by company multipliers that is calculated based on

performance against fixed metrics that are established at the beginning of the year, and that can range from zero to, I believe, upwards of 1.5 or 2, somewhere in there. Then it's also multiplied by a personal multiplier based on individual performance for the year, based on a review process that occurs at the end of the year. Looking at how an individual performs against their objectives. And that, again, can range from anywhere from zero to 1.8, I believe.

So those multipliers depending on individual performance and company performance can translate to a bonus that is somewhere between zero percent and somewhere north of a target percentile for an individual position.

MR. NOEL: So for instance, if you're base salary was 100,000 then you start off with a target of 15,000, correct?

THE WITNESS: That is correct.

MR. NOEL: And on that, what would be the maximum bonus that you could get?

THE WITNESS: I don't know the answer to that question.

MR. NOEL: And how much were those bonuses tied to safety?

THE WITNESS: I don't know the answer to that question. I'm varying the -- the metrics and the percentage of those metrics under different categories

fluctuated year over year.

MR. NOEL: So, for instance, 2017 was a very bad year in terms of safety metrics. Do you recall if you got a bonus in 2017?

THE WITNESS: Yes, I previously answered that. Bonuses were given out. I don't remember the amount.

MR. NOEL: You had a follow-up?

BY MS. DUPRE-TOKOS:

Q. Yeah, just a couple of quick follow-ups?

So you said that with regarding to communicating to those higher up the food chain than you about the dangers of wildfire. You said it would be consistent with what was included in the 2017 RAMP filing. Did I get that right?

A. That is correct.

Q. Okay. But you did not recall when you notified them. Was it pre RAMP filing?

A. I don't know a hundred percent. I would assume so. The notification I was referencing is part of the integrated planning process. We didn't get a chance to touch into that, but we have a session D, which is -- I actually don't know why it's called Session D. It came over with a previous chief executive officer from another utility back east. And it's a framework for systematically evaluating risks and laying the risk -- enterprise risk of the foundation for informing our

planning process for our future investment plans. In that context, wildfire was regularly a topic that we brought as electric operations to that forum in order to highlight the current state of wildfire and the associated mitigations being employed to help manage that growing risk.

Q. Generally, what time of year was that meeting so that you can have the -- the plan, you know, done by a certain time?

A. I believe that was in the early part of the year. Q1, usually.

Q. Okay.

A. We discontinued that methodology with change in our execute leadership, so we haven't had one this year.

Q. Okay. So that just stopped this year? Well, in 2019 or 2020?

A. I believe it officially stopped in 2020. I think there was still a session D in 2019, if I'm not mistaken.

Q. Okay. Be your recollection is that you probably addressed the issue of severe wildfire risk with Kevin Dasso and Hogan?

MR. NOEL: Patrick Hogan.

THE WITNESS: Pat Hogan.

BY MS. DUPRE-TOKOS:

Q. Yes. And then Geisha Williams, prior to the RAMP filing in 2017?

A. Let me correct that statement. I actually don't know whether it was before or after the filing of the 2017 RAMP.

Q. Okay. Do you know when the filing of the 2017 RAMP was?

A. No.

MS. DUPRE-TOKOS: Does it say on there, Marc?

MR. NOEL: It doesn't have a date on it, but it refers to 2017 wildfires which occurred in October, so it was sometime after that.

THE WITNESS: It's dated November 30, 2017.

MR. NOEL: Ah, does have a date.

BY MS. DUPRE-TOKOS:

Q. Okay. So you think it was probably somewhere around then that you notified them?

A. Would have been either -- actually, I don't recall. I apologize.

Q. Okay. But it was prior to, say, March of 2018, in all likelihood?

A. I don't know for sure, but that's what I would assume.

Q. Okay.

A. That timeframe.

Q. Okay. So then my last follow-up is -- and I know we went over it, but this -- the question that was asked by the jury kind of looked at it from a different angle so

I want to follow up.

You said that when you are coming up with your -- you're doing your planning and you're looking at the different factors including risk, you assume that people and the data you're getting are trustworthy. It's not anecdotal. But do you just place blind trust in the people who are giving you that information, say, the people from the field? You don't know any of them, do you? You've never worked with them, have you?

A. Many, no.

Q. Okay. So I understand that you have to have some level of trust on -- in all the aspects, but have you ever done anything to just kind of spot check to make sure anything is right?

A. So I would say we have done assessments of our programs and I think that was highlighted a bit in the RAMP, or in the asset management plan where we highlighted the -- what looked to be black to clear, but it's actually color coding, so that's part of our risk assessment process where we have evaluated the health and maturity of the programs as a whole. Those are done outside of my organization, but I have received presentation on materials that have characterized on the -- on the level of maturity how well functioning certain processes are.

But in terms of going out to the field and witnessing certain tasks; unfortunately, I haven't had the

bandwidth to be able to do that in addition to the responsibilities that I am -- that I am being trusted to perform on behalf of the company.

Q. So are any of those programs that have been assessed for their health, the inspection program?

A. Yes. That -- that part of that process is to evaluate existing controls and inspection -- inspection programs have been a regular control in that overall risk framework.

Q. Okay. Did that change after San Bruno?

A. I don't recall.

MR. NOEL: A couple.

MS. DUPRE-TOKOS: We feed off each other, sorry.

BY MR. NOEL:

Q. Right. You mentioned that Session D was initiated by former chief executive who came from another utility, would that be Geisha Williams?

A. No.

Q. Was it in place before Geisha Williams?

A. I believe Geisha was with the company before it was implemented, but I don't believe she was CEO --

Q. Okay.

A. -- until after it was implemented.

Q. Who was the CEO before Geisha, Tony Earley?

A. That is correct.

Q. And that also -- it just dawned on me, the RAMP.

That's a -- that's essentially a policy statement that is being filed with the regulator, correct?

A. What do you mean by "policy statement"?

Q. It's setting out explaining what PG&E is doing as a matter of policy to address these -- these risks -- identified risks, correct?

A. I would characterize it more as a summary of the modeling that we did at the direction of the CPUC.

Q. Okay. Was the RAMP reviewed with the senior officials -- Kevin Dasso, Patrick Hogan, Geisha Williams, prior to being filed with the CPUC?

A. Yes.

MR. NOEL: Okay. Anymore further follow up? I think you're finally done, Mr. Gabbard. We appreciate your -- Madam Foreperson is going to have another admonition for you.

GRAND JURY FOREPERSON: Mr. Gabbard, you are admonished not to discuss or disclose at any time outside of this jury room the questions that have been asked of you or your answers until authorized by this grand jury or the Court.

A violation of these instructions on your part may be the basis for a charge against you of contempt of court. This does not preclude you from discussing your legal rights with your own attorney.

Mr. Gabbard, what I have just said is a warning

EXHIBIT E

CAL FIRE NEWS RELEASE

California Department of Forestry and Fire Protection

CONTACT: Michael Mohler
Deputy Director
Phone: (619) 933-2357
calfire.dutypio@fire.ca.gov

RELEASE DATE: January 24, 2019

CAL FIRE Investigators Determine the Cause of the Tubbs Fire

Sacramento – After an extensive and thorough investigation, CAL FIRE has determined the Tubbs Fire, which occurred during the October 2017 Fire Siege, was caused by a private electrical system adjacent to a residential structure. CAL FIRE investigators did not identify any violations of state law, Public Resources Code, related to the cause of this fire.

The Tubbs Fire in Sonoma County started on the evening of October 8th, 2017 and burned a total of 36,807 acres. Destroying 5,636 structures and resulting in 22 civilian fatalities and one firefighter injury.

In total, the October 2017 Fire Siege involved more than 170 fires and burned at least 245,000 acres in Northern California. Approximately 11,000 firefighters from 17 states and Australia helped battle the blazes.

CAL FIRE investigators are dispatched with the initial attack resources to the wildfires in CAL FIRE jurisdiction and immediately begin working to determine their origin and cause.

Californians must remain vigilant and take on the responsibility to be prepared for wildfire at any time throughout the year. For more information on how to be prepared, visit www.readyforwildfire.org or www.fire.ca.gov.

# # #

Media Note: Link to the redacted Tubbs Investigative report
http://calfire.ca.gov/fire_protection/fire_protection_2017_siege

EXHIBIT F

UNITED STATES BANKRUPTCY COURT

NORTHERN DISTRICT OF CALIFORNIA

-oOo-

In Re: PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY Debtors.	Case No. 19-30088 Chapter 11 San Francisco, California Wednesday, January 24, 2024 10:00 AM

STATUS CONFERENCE REORGANIZED DEBTORS' OBJECTION TO PROOF OF CLAIM NO. 2090 FILED BY AMIR SHAHMIRZA [12130]

PERA'S MOTION FOR APPOINTMENT AS LEAD PLAINTIFF AND APPROVAL OF SELECTION OF LEAD COUNSEL FILED BY SECURITIES LEAD PLAINTIFF AND THE PROPOSED CLASS [14169]

DISCOVERY RULING ON REORGANIZED DEBTORS' THIRTY-THIRD SECURITIES OMNIBUS CLAIMS OBJECTION TO PERA AND SECURITIES ACT PLAINTIFFS' TAC, INCLUDING CERTAIN CLAIMANTS THAT ADOPTED THE TAC FILED BY PG&E CORPORATION [14200]

DISCOVERY RULING ON REORGANIZED DEBTORS' THIRTY-FOURTH SECURITIES CLAIMS OMNIBUS OBJECTION TO CLAIMS ADOPTING RKS AMENDMENT FILED BY PG&E CORPORATION [14203]

DISCOVERY RULING ON REORGANIZED DEBTORS' THIRTY-FIFTH SECURITIES CLAIMS OMNIBUS OBJECTION TO BAUPOST AMENDMENT FILED BY PG&E CORPORATION [14206]

TRANSCRIPT OF PROCEEDINGS
BEFORE THE HONORABLE DENNIS MONTALI
UNITED STATES BANKRUPTCY JUDGE

APPEARANCES (All present by video or telephone):

For the Reorganized Debtors:	STEVEN A. LAMB, ESQ. Rovens Lamb LLP 2601 Airport Drive Suite 370 Torrance, CA 90505 (310)536-7830
	THOMAS B. RUPP, ESQ. Keller Benvenutti Kim LLP 650 California Street Suite 1900 San Francisco, CA 94108 (415)636-9015
	Richard W. Slack, Esq. Weil, Gotshal & Manges LLP 767 Fifth Avenue New York, NY 10153 (212)310-8000
	Joshua G. Hamilton, Esq. Latham & Watkins LLP 10250 Constellation Boulevard Suite 1100 Los Angeles, California 90067 (424)653-5500
For Amir Shahmirza, Komir, Inc.:	LAWRENCE A. JACOBSON, ESQ. Cohen and Jacobson, LLP 66 Bovet Road Suite 285 San Mateo, CA 94402 (650)261-6280
For PERA:	MICHAEL S. ETKIN, ESQ. Lowenstein Sandler LLP One Lowenstein Drive Roseland, New Jersey 07068 (973)597-2500

For RKS Claimants: FRANK T.M. CATALINA, ESQ.
Rolnick Kramer Sadighi LLP
1251 Avenue of the Americas
New York, New York 10020

Also Present: Amir Shahmirza, Claimant

Court Recorder: LORENA PARADA
United States Bankruptcy Court
450 Golden Gate Avenue
San Francisco, CA 94102

Transcriber: RIVER WOLFE
eScribers, LLC
7227 N. 16th Street
Suite #207
Phoenix, AZ 85020
(800) 257-0885

Proceedings recorded by electronic sound recording; transcript provided by transcription service.

SAN FRANCISCO, CALIFORNIA, WEDNESDAY, JAN. 24, 2024, 10:01 AM

-oOo-

(Call to order of the Court.)

THE CLERK: Court is now in session, the Honorable Dennis Montali presiding. Calling the matter of PG&E Corporation.

THE COURT: Morning. Mr. Jacobson.

MR. JACOBSON: Good morning, Your Honor. Lawrence Jacobson for claimant Komir, Inc. Mr. Shahmirza is present here with me. He is off camera.

THE COURT: Muted. Mr. Lamb, you're on mute.

Mr. Rupp, you want to speak for him?

MR. RUPP: Good morning, Your Honor. Thomas Rupp of Keller Benvenutti Kim for the reorganized debtors. And not to state the obvious, but I take it Your Honor is taking this matter first and all of the security stuff next?

THE COURT: We are. That's true.

MR. RUPP: Very good.

THE COURT: All right. Mr. Lamb, you turned your mic on. Good morning.

Mr. lamb, can you hear me?

Mr. Jacobson, you can hear me, can't you?

MR. JACOBSON: I can. These kind of connection issues are a source of great anxiety every time.

MR. LAMB: Madam clerk, is there audio on? I cannot

hear anything.

THE CLERK: Yes. Mr. Lamb, can you hear us?

THE COURT: We can hear you, Mr. Lamb.

Well, I wonder if Mr. Lamb has his own setting too low.

Well, Mr. Rupp, I set this one first because it would be -- I thought it'd be quick.

MR. RUPP: Your Honor, do you think you could -- if it's all right with everyone, could you trail it while we get Mr. Lamb sorted out?

THE COURT: Well, I'll have to do that. But I've got much longer chunk of time reserved. I'd like to just see if he's made any progress.

Mr. Lamb, can you hear me yet?

Well, I guess we'll have -- we have no choice on that.

MR. JACOBSON: Well, maybe he could -- excuse me. Maybe he could call in on the telephone for the audio part?

THE COURT: Ms. Parada, can we do that? Can we tell him to do that?

THE CLERK: I can send him an email, Your Honor. He can't hear us to give him those directions.

THE COURT: Okay. Well, we'll see if we can get this fixed in a minute or two because I don't want to delay it extensively, but I also don't want to wait too long for the other counsel coming up in the next matter.

So Mr. Lamb, are you -- or Mr. Rupp, are you in direct communication with him? You could also call him on his phone and tell him to call in on it on the audio.

MR. RUPP: Oh, Your Honor, I would need the instructions from Ms. Parada on how to call in and if that's possible.

THE COURT: No, that's what I said. I said you could call Mr. Lamb on your telephone the old fashioned way and tell him to call in on the audio line or do something or to reboot or do something.

Well, Ms. Parada, did you send him something?

THE CLERK: I did. I did inform him that we can hear him and that -- I will mute him.

THE COURT: Okay. Mr. Lamb, how about now? Can you hear me?

Well, we'll wait a minute or two. That's about it. I almost canceled this hearing and just sent out a message giving you a trial date now, but we decided to wait.

So Mr. Jacobson, your comment confuses me. I mean, I --

MR. LAMB: I'm still not hearing anything.

THE COURT: Oh.

THE CLERK: Mr. Lamb, can you hear us?

THE COURT: Mr. Jacobson, my question to you, you commented about frequent problems. You mean through the court

or with Mr. Lamb?

MR. JACOBSON: Oh, no. With the court, state court and federal court. There's always that moment of anxiety where everybody else is connected and they're saying, counsel, counsel. And you're trying to figure out what's wrong and bad things get worse and it's very frustrating. I can empathize with Mr. Lamb.

THE COURT: Oh, I hate to tell you, we've had a pretty good record. Maybe it's the A team at work here for you.

Mr. Lamb, last chance. Can you hear me?

All right. Well, gentlemen, I'll just have to try you at the end of the calendar -- not the end, but we did set aside about forty minutes for --

MR. LAMB: Great. I can't hear anything.

THE COURT: Well, okay. Obviously, I think the problem must be at Mr. Lamb's end and --

THE CLERK: Yes, Your Honor.

THE COURT: -- we can hear him, so something's working. It's probably nothing more than a setting on his own audio, and which might just be a simple -- he needs a teenager in the room to come in and fix it for him. But I'm going to move the Shahmirza matter off after the next matter.

So I'm sorry, Mr. Jacobson and Mr. Rupp. I'm going have to do it that way. So --

MR. JACOBSON: Very good, Your Honor.

THE COURT: Okay. Okay. Ms. Parada, go ahead and call the next item on the PG&E case.

THE CLERK: Taking the PERA motion, Your Honor.

THE COURT: Yes.

THE CLERK: If I can just have counsel that will appear to raise a hand, please.

THE COURT: Morning, Mr. Slack. Just state your appearance, please.

MR. SLACK: Good morning, Your Honor. Richard Slack from Weil, Gotshal & Manges for the reorganized debtors.

THE COURT: Mr. Catalina, are you going to make an appearance?

MR. CATALINA: Yes. Good morning, Your Honor. Frank Catalina of Rolnick Kramer Sadighi for the RKS claimants.

THE COURT: Okay. Mr. Etkin, are you making the argument today?

MR. ETKIN: I am, Your Honor. Can you hear me?

THE COURT: Okay. State your appearance, and then let's get underway.

MR. ETKIN: Okay, Your Honor. Michael Etkin, Lowenstein Sandler, for PERA.

THE COURT: Mr. Hamilton, are you making an appearance today?

MR. HAMILTON: Yes, Your Honor. Joshua Hamilton of Latham & Watkins for the reorganized debtors. Good morning.

THE COURT: Okay. Ms. Parada, why don't we take Mr. Lamb and Mr. Jacobson off the screen for now.

THE CLERK: Yes, Your Honor.

THE COURT: Okay. All right. Mr. Etkin you've got my order for argument time. You ready to do that?

MR. ETKIN: I am, Your Honor, and I do have your order. And I intend to try and accomplish what you've asked.

THE COURT: How much time do you want to reserve?

MR. ETKIN: I want to reserve eight minutes --

THE COURT: Okay.

MR. ETKIN: -- for rebuttal, Your Honor.

THE COURT: Okay. Let's do it, and let's get underway. Go ahead.

MR. ETKIN: Okay. Well, good afternoon, Your Honor. Good morning to you, I guess.

THE COURT: It is.

MR. ETKIN: As the Court notes, a Rule 23 process working alongside the claims procedures is unusual. That's what the Court wanted, a dual process. And there's no basis to say that it's not working. It's not our intention to interfere with that process and the dual track. But we do want to do our job, and we do want to make sure that we fulfill our fiduciary obligations.

What is not unusual, Your Honor, in the context of Rule 23 is the idea of a representative plaintiff and a

representative counsel being appointed pre-certification to deal with substantive challenges to the securities claims, which are at the core of this whole situation. In fact, as we noted in our motion and our reply and as the Court noted in its tentative ruling, Rule 23 specifically contemplates the appointment of interim class counsel.

So let me get to the core question that the Court posed in its interim ruling. And I'll quote it rather than paraphrase it. "Just what PERA and its counsel expect to be able to do as interim class representatives, consistent with PERA's commitment that it does not intend to improperly intercede in the ADR procedures," the Court went on to say that that statement seems at odds with the accompanying statement at footnote 8, that PERA reserves all rights to object to the reorganized debtors' omnibus objections.

Now, as a threshold matter, Your Honor, there was no intention for those two statements to be at odds with one another.

THE COURT: Well, listen, let me simplify it for you. You've been actively representing PERA since the case began. And by the way, some of you might know, and Mr. Slack will remember, I believe we're coming up one week from now to the fifth year on the case. All right. You've been here since the beginning, I believe. But if I grant your motion, as my tentative indicated I would, you take on, it seems to me, a

slightly different relationship with other claimants.

So I won't doubt that you can continue to represent PERA whether you are a representative or not. But the question is what happens to an individual claimant or a represented claimant, either one, who are on their own and they're defending the omnibus objections? What is your and PERA's relationship to those that individual or that represented individual if I authorize the interim class label to be added to your role here?

MR. ETKIN: Well, Your Honor, as interim class counsel and with PERA as interim representative plaintiff, the one thing that's top of mind is to deal with these sufficiency objections, which go to the heart of the securities claims.

THE COURT: Which ones? The ones against your claim, which is fine, but what about the sufficiency objections directed to another claimant?

MR. ETKIN: It would be on --

THE COURT: My hypothetical claimant who's on his own.

MR. ETKIN: Well, Your Honor, as we said in our motion, it's not our intention to in any way represent or take positions on behalf of claimants who are individually represented in the case.

THE COURT: Mr. Etkin, you're going around in circles.

MR. ETKIN: Well, it's those claims --

THE COURT: The debtors' counsel has filed enormous

numbers of objections, and the PERA one is a standalone. It's the thirty-third -- or maybe it's the thirty-fifth -- thirty-third omnibus, and that's easy for me to resolve. I'm talking about Mr. X, Mr. X who filed a small claim for 20,000 dollars, hypothetically, and PG&E has objected. And Mr. X says, I'm owed 20,000 dollars. And I suspect that that Mr. Slack will ask that I strike that claim as not stating a viable claim.

My question is what do you do about Mr. X, who in a nonbankruptcy setting, maybe you would speak for Mr. X because he's a member of the putative class, but do you stand up at the podium and argue for Mr. X on the whatever omnibus objection he's opposing, or are you quiet on him? And that's what I need you to clarify what you do.

MR. ETKIN: Well, I --

THE COURT: So what do you do about Mr. X, who's standing there, saying, I've got a good claim for 20,000, and Mr. Slack wants to toss it?

MR. ETKIN: Well, we would be filing opposition to the sufficiency objections on behalf of the --

THE COURT: On behalf of Mr. X?

MR. ETKIN: On behalf of Mr. X and anyone else who's out there who's the subject of a sufficiency objection that is not represented by independent counsel.

THE COURT: Okay. So Mr. X says --

MR. ETKIN: Your Honor, I see no difference --

actually, I see no difference here with a situation outside of bankruptcy which happens all the time in securities cases under Rule 23, where --

THE COURT: How many times, Mr. Etkin? How often in a nonbankruptcy securities class action does the defendant challenge the standing by filing an objection to a claim of a member of the class before there's any certification?

MR. ETKIN: I don't know. Your Honor, I confess, I don't know what you mean by challenging the standing. But I don't --

THE COURT: Mr. X shows up at the district court and says, I want to be heard. I want to say something and --

MR. ETKIN: He's entitled to be -- he's entitled to be heard.

THE COURT: Okay.

MR. ETKIN: We're not foreclosing any individual claimant from coming into court and wanting to be heard. What we're doing is making sure that claimants who are unrepresented, that claimants who are not coming into court, that we advance a position in opposition to the sufficiency objections that challenge fundamentally the claims that all of these securities claimants are asserting and have asserted.

THE COURT: Okay. And you believe you're able to do that once I grant your motion under 23(g)(3). And even then, there's no conflict with PERA, your actual client, on a

different set of objections.

MR. ETKIN: With respect to the sufficiency objections, which challenge the securities claims at their core, we have the ability and Rule 23 contemplates, and Rule 23 is now applicable here, recertification. Rule 23 contemplates that an interim counsel can come in on behalf of absent class members to make the arguments to sustain, at least on a preliminary basis, the allegations that are made by each of these individuals by filing a claim.

Your Honor, it's interesting. I went back, and I took a look at the proof of claim. And really, that proof of claim is even structured based certainly in part, at least, on the PERA complaint. When you look at the time frame of the purchases, it all ties into the PERA complaint.

So it's obviously simple with respect to those that adopted the PERA complaint directly. But even those that didn't, these allegations, which the debtor is now challenging, are at the core of all of these claims. And I don't think the Court ever had an expectation that hundreds of securities claimants would come in with hundreds of lawyers, filing hundreds of documents, in opposition to what the debtor refers to as a motion to dismiss.

THE COURT: Yeah, I don't know. Frankly, I didn't know what to contemplate. All right. So let me phrase the question a little more specifically and then I'll call on the

opposing counsel and then let you respond.

But what do I do for an actual, real person, a real Mr. X, who is on his own, and he has, in fact, filed an opposition to one of the omnibus objections, the one that was directed at him? Do you purport to then take over the argument for him? Do you purport to be his lawyer? So you have X is unrepresented, on his own, and is filed a pro se opposition to the omnibus objection. What is your role vis-a-vis Mr. X under that situation?

MR. ETKIN: If that were an actual situation, we would certainly reach out to that Mr. X. But we would take the position that obviously the Court would need to pay attention to whatever Mr. X filed if he chose to file something on his own. But what we're filing in his case would at the very least be a supplement to that and would be something for the Court to consider.

THE COURT: Okay.

MR. ETKIN: While the Court is considering these sufficiency objections, each of which -- and I'm not talking about the RKS situation. They're on their own. I'm not talking about the Baupost situation. They're on their own, unless they tell us something different. But aside from that, each of the other objections from the twenty-eighth through the thirty-eight are in whole or in part sufficiency objections with respect to the underlying securities claims.

THE COURT: Okay. Mr. Etkin, let's hold it at that point. Let me just make one comment. This is not asking you to respond.

I will just tell you, if you look at our docket, which is voluminous, you will see already there are Mr. Xs that are filing on their own in response to the omnibus objections. And we've got two weeks to go for the first round of omnibus objections that are not on the thirty-third, thirty-fourth, and thirty-fifth. You and Baupost and RKS are on a different timetable.

And so all I'm saying is that I have to have -- you've given me the answer. And when I ask you to make your rebuttal argument, if you have any refinement to that, I just want to know what you perceive to be your role. Just take my word for it, the docket already reflects, let's say unrepresented, or at least apparently pro se claimants, who are fighting back on the omnibus objections without your kind of expertise and so on.

So don't comment now. I want to move along. And I'll come back --

MR. ETKIN: The only comment I'll make, Your -- if you permit me, Your Honor, the only comment I'll make is that I've seen two of those pro se --

THE COURT: Okay.

MR. ETKIN: -- objections or statements, and all that says to me -- and I'll comment further later, but all that says

to me is that these people need an interim counsel to come in and take substantive positions on their behalf.

THE COURT: Okay. Mr. Hamilton, are you making the argument, or Mr. Slack?

MR. HAMILTON: Mr. Slack's going to start, Your Honor.

THE COURT: Okay. I just wanted (indiscernible) --

MR. SLACK: Yeah.

THE COURT: -- Mr. Slack.

UNIDENTIFIED SPEAKER: Good morning, Your Honor.

MR. SLACK: Yeah. And Your Honor, the RKS folks are going to get five, and I'm going to give a couple of minutes to Mr. Hamilton at the end to address one more discrete issue.

THE COURT: Okay. Thank you.

MR. SLACK: So Your Honor, I also apologize that my internet went out. So I don't know whether anybody noticed I was not on the screen for a while. So I missed much of what Mr. Etkin said. So I'm not really in a position to respond to a great deal of it. But let me make the following point to start, which is --

THE COURT: You want me to take a break so you can listen to the audio?

MR. SLACK: Well, I'm not sure -- I'm not sure I even know how to go back and do that, Your Honor.

THE COURT: Okay. And go ahead and make your argument. You're a capable --

MR. SLACK: Yeah.

THE COURT: -- experienced lawyer.

MR. SLACK: So Your Honor, Your Honor's tentative ruling got the most important point exactly right, and that is that the apparent real purpose of PERA's motion is inconsistent with the Court's two prior rulings that PERA doesn't have standing to object to the omnibus objections directed at the claims of other claimants. And PERA's motion, which is interesting, I mean, when you look at their motion, was entirely silent on what it meant to be interim counsel. And the case law they cite, and this is important, provides absolutely no basis for interim counsel to be able to appear on behalf of separate claims brought by individual claimants. There is zero cases that do that.

And the reason for the silence in the motion, and quite frankly, for the confusion on the meaning of what the motion would mean stems from the fact that Rule 23(g)(3) was not intended to apply in this situation. I mean, I note that Mr. Etkin says that it's not unusual for interim counsel to be appointed under 23(g)(3), and I guess I would say this. It's not only unusual in this situation, it's completely unheard of. And that's because when you understand the purpose of Rule 23(g)(3), you understand why PERA can't do any of which they're actually suggesting they should be able to do.

The advisory notes to Rule 23(g)(3), which PERA cites

only in part in their reply, makes clear that 23(g)(3) is designed for a different situation than present here. Rule 23(g)(3) is meant to apply where there are competing counsel or competing cases where there are multiple counselors saying, Judge, let me represent the class.

THE COURT: Well, I know that.

MR. SLACK: And the court --

THE COURT: I know that but -- I know that, but you know what, Mr. Slack, as long as you've been appearing before me, I've never recall once that you have not even cited a rule that you think is dispositive. I mean, I found it amazing that that not a single reference to 23(g) in your papers. So what do I do now?

MR. SLACK: Yeah.

THE COURT: The words of the Rule are pretty clear.

MR. SLACK: So let me explain that, Your Honor.

THE COURT: Well, I mean, I --

MR. SLACK: Yeah, let me explain that, Your Honor.

THE COURT: But what I'm saying is, you know what the rule about we don't consult the actual text of the statute if the legislative history is clear. Well, the text of the Rule here is pretty clear. The court may appoint interim counsel.

MR. SLACK: I actually disagree with that, Your Honor.

THE COURT: Okay.

MR. SLACK: I mean, I think that the -- I think

that -- I think that -- I think that at least the cases, and I'm going to cite you a couple if you give me the leeway to do it in your own district by district court judges, state that Rule 23(g)(3) is designed only for the situation where there's competing counsel. And what's interesting is that it's not only the advisory notes that say this. Right.

When you look at the key cases -- I mean, for example, in Donaldson v. Pharmacia, which is 206 WL 1308582 from the Southern District of Illinois, in that case, the court said, importantly, both the commentary to Rule 23 and the Manual For Complex Litigation, Fourth indicate the appointment of interim counsel is not appropriate. Whereas here, a single law firm has brought a class action and seeks appointment as class counsel. And then they said, consistent with the commentary to Rule 23 and the manual, the court's research indicates that the kind of matter in which interim counsel is appointed is one where a large number of putative class actions have been consolidated or otherwise are pending in a single court.

And recently, Judge Nunley in the Eastern District of California adhered exactly to that. He denied appointment of interim counsel, holding that, "There is no indication of rival cases exist that might justify appointing interim counsel." And that's in Brooks v. Tapestry, 2022 WL 956872, from March of 2022.

And he's not the only judge in California that said

that. Judge Alsup recently similarly denied interim class counsel and recognized, "The typical situation requiring appointment of class counsel is one where a large number of putative class actions have been consolidated or are otherwise pending in a single court.

And Judge White --

THE COURT: Okay. Mr. Slack. Mr. Slack, again, I'm not even writing down the cases right now. I might ask you to file a brief statement that set forth the sites.

But my point is, not a single one of them involves a parallel track. But more importantly, is there any reason to believe that the rule makers themselves, the Supreme Court, when they promulgated the Rule, limited it to this multiple class situation? Because it doesn't say so. It doesn't limit. The language of sub (3) doesn't limit it to when there are multiple cases or multiple counsel competing.

MR. SLACK: Well, let me just say that Judge White, also, from the Northern District of California, his holding denying interim class counsel is "Where there are no competing lawsuits or firms, courts in this district have been unwilling to appoint interim class counsel."

THE COURT: Okay. Okay. All right. All right.

MR. SLACK: And the point -- and the point is, Your Honor, and I think it's really important, the purpose of the Rule is where you have these competing counsel, the defendants

actually need to know who they're going to deal with to file class certification and to who's going to do discovery on the class certification. It's purely a Rule -- and that's what the advisory opinion -- the advisory notes say. It's purely a Rule that's designed to deal with this particular problem.

When you understand it, in that you get the reason why -- and this is critical, Your Honor -- there is not a single case, zero, null set, that has ever expanded the powers of counsel to go and appear for people who have filed individual claims, whether in the bankruptcy or out of the bankruptcy. And in fact, zero. There's not any support that PERA has given. Zero. I keep saying zero because it's zero. The meaning of interim counsel doesn't expand their role at all.

THE COURT: Is there a single case or a zero case that has denied a request like this one with one class, one request? And the score is zero to zero, I guess. There's no case either way, right?

MR. SLACK: No. No, it's not. There's Judge White --

THE COURT: Well, I know you said Judge White. Did any of the other cases deny a request of a counsel such as Mr. Etkin and his colleagues representing only one group, rather than competing?

MR. SLACK: It doesn't. Doesn't.

THE COURT: Hmm?

MR. SLACK: Doesn't. And in fact, if you go to -- if you go to -- if you go to Judge White's case, which is In re: Seagate Technology, which is Northern District, California, where he said that where there's no competing firms, courts in this district have been unwilling to appoint interim class counsel, he cites a dozen cases in your district. Where there's only one competing counsel, it was denied. He cites six of them. I cited another three here, which I can do. And the point is is that, Your Honor, it is well known -- and had they done --

Look, here's what's really crazy, Your Honor. They made a motion, and they're experienced securities counsel. They made a motion. They said they want to name a lead plaintiff, lead plaintiff, and lead counsel. Now, that is a term of art, and that's a term of art in the PSLRA. And there's no support in the Federal Rules for that.

So what did they -- what did they say in their reply? Well, they said, Judge, we cited Rule 23(g)(3). Well, you know what they did. They cited Rule 23(g)(3) in a footnote without any discussion. They didn't say any cases that support what they're doing. They didn't say what the purpose was. They didn't say under 23(g) that there was any process they had to follow. It was a cite in a footnote without any discussion whatsoever. And let me tell Your Honor, when you get a counsel as a security -- a brief as a securities lawyer that says lead

plaintiff and lead counsel, that's not 23(g)(3).

One other thing, Your Honor. Look at their motion. They want to appoint a lead plaintiff first and then lead counsel. Rule 23(g)(3) does not even address lead plaintiff or an interim --

THE COURT: No, I know that. I'm aware of that.

MR. SLACK: And so the idea --

THE COURT: But therefore, what?

MR. SLACK: The idea that this, that they're --

THE COURT: But therefore, what?

MR. SLACK: Therefore, Your Honor, I'm just saying -- I'm just saying that you haven't had the opportunity to have that issue briefed in front of you because they didn't put it in their -- they pivoted from saying, we want lead plaintiff and lead counsel, which is a term of art in the PSLRA.

THE COURT: Thank you. I got it.

MR. SLACK: And so all of this -- all of this case law that I'm citing to you that says that what they're doing is completely inappropriate, you didn't have the opportunity to see when you did your tentative.

And the point I'm making, Your Honor, is that when you understand 23(g)(3) in light of its purpose, it doesn't expand anybody's -- it doesn't expand counsel's role in any way. All it does is it tells everybody, the defendants and everybody, who is going to be the counsel that's doing things like filing

the class certification motion. Otherwise, if the Court didn't do that when there's competing counsel and competing cases --

THE COURT: Okay. Okay. I get it.

MR. SLACK: -- you'd never have an idea of who was going to -- who was going to be involved.

And so Your Honor, I would say one other thing, which is really important here. One of the reasons that courts don't just nilly-willy when there's no competition appoint an interim plaintiff -- or not -- an interim counsel is because it accelerates certain aspects of the class certification motion. What 23(g)(3) says, and I think it's important, Your Honor, is that you apply the same standard for counsel as you would in class certification. And so when you seek to apply interim counsel and you do it when there's -- you may need to do it if you're a court when there's competing counsel because you have to pick between counsel. But otherwise, what you're doing is you're accelerating part of the class certification determination.

And what I'll tell Your Honor is that prejudices us here because Your Honor said specifically when we dealt with class certification that issues of typicality and adequacy, which are the two that they dealt with in their opening motion, all right, what Your Honor said was that we were entitled to discovery. You were not making any determination on the merits.

THE COURT: No, I acknowledge that.

MR. SLACK: What's happening here is that in order to make an appointment of interim counsel, you're reversing that decision and prejudicing us. And that's not appropriate, especially when Rule 23(g)(3) was never meant to be applied in this context.

So what I would tell Your Honor is there is a process that was set out in the amended objection procedures. That process is working. We have had over thirty omnibus objections. Individuals have either objected or they haven't. But the point is individuals over this -- individual claimants have either appeared or not, but Your Honor has granted objections where individuals have appeared, where they haven't appeared, and each individual is responsible for that. And twice, Your Honor has ruled that PERA can't step in and do that.

THE COURT: No, you're just repeating. You're repeating yourself now. Let me call on Mr. Catalina for his comments, and then I'll figure out what to do next.

Mr. Catalina.

MR. SLACK: Thank you, Your Honor.

MR. HAMILTON: Your Honor, I have one comment to add to Mr. Slack, if I may.

THE COURT: Yes, sir.

MR. HAMILTON: Thank you.

THE COURT: Mr. Hamilton.

MR. HAMILTON: Thank you, Your Honor. Your Honor, I just want to address briefly your comment on the PSLRA specifically applying to this situation. I'm really building on what Mr. Slack said. There is consequences to PERA citing Rule 23(g) because as Your Honor knows, the PSLRA already has two specific points -- two sections that specifically apply to any private right of -- any private action under this Chapter. And the lead plaintiff process specifically applies where an action is brought pursuant to the Federal Rules of Civil Procedure.

And so by invoking Rule 23, and Mr. Etkin specifically said Rule 23 is applicable here, Rule 23, then, this is a -- this is unquestionably a Securities Act and Exchange Act claim brought in the bankruptcy court, a private action pursuant to the Federal Rules of Civil Procedure. So if to the extent that they're even trying to invoke Rule 23(g), they have to then accept the lead plaintiff proposition from the PSLRA.

THE COURT: Look, I'm not going to repeat what I said. You all know, all you securities lawyers particularly know, that the bankruptcy courts generally and this bankruptcy judge doesn't have much occasion to deal with class actions. It just so happens that I was, in fact, in a -- did a nationwide class certification in the Teran case, which is on just about a done deal now through another court. But it's rare. I mean, I've

talked to other colleagues and mentioned about the rarity of a traditional class action. And it's true.

So this judge gets a motion that cites a Rule that have no occasion to look at ever and read it. And I then got responses from very experienced counsel that never even mentioned the Rule. And it was sort of like, how can I ignore the plain meaning of 23(g)(3). End of story. So I'm not complaining or criticizing you all. I'm saying, you got a handful of arguments now about all these ramifications. And we have this case on this record and this decision, and here we are.

So anyway, Mr. Catalina, you have a couple of moments here.

MR. CATALINA: Thank you, Your Honor. I'll be brief. Just a couple things I want to address. First, and most important to the RKS claimants, we did see in PERA's papers an apparent shift in the class definition to exclude the RKS claimants and most expressly in their reply, where they say that the RKS claimants are explicitly excluded from the proposed class. I think that's consistent with what I heard Mr. Etkins say before. But most important to us, certainly, is that nothing that would be done by a lead plaintiff or a lead counsel would have any effect on the RKS claimants' claims. And I just want to get that out there. And I think that's consistent with everything PERA's said.

THE COURT: Well, it's consistent with -- it's certainly consistent with the way we've discussed the briefing for the sufficiency things, the way the omnibus objections are broken out, and everything else. So it's never been my even slightest imagination that Mr. Etkins' trying to poach on your turf or Baupost's turf.

MR. CATALINA: I understand, Your Honor. In the 7023 --

THE COURT: Okay.

MR. CATALINA: -- motion, the class definition would seem to subsume even the RKS claimants. It seems from the latest submission that that's not the case. And from what Mr. Etkins said, I just want to put that on the record. That's all.

THE COURT: Okay.

MR. CATALINA: The second point that we want to make is our understanding of Your Honor's thinking on the certification of a class is that in part, it stems from the idea that we get through these ADR procedures and sufficiency objections and there may be some number of claims left with a diffuse claimant group and how is the Court going to manage those claims.

Consistent with that, we think that, although we don't understand what a lead plaintiff is in this situation, we think that if the Court is looking for a way to define a lead

plaintiff role, what makes the most sense is to get beyond the sufficiency objection stage. And when we get there, we're getting to a place where now there are going to be some number of claims left over to litigate. And there's going to be discovery. At that point, we think it would be efficient for the resolution of these claims, certainly, if PERA stepped in and was the party at the table in the discovery coordination and case management coordination discussions at that point that kind of represented the interests of the remaining nonrepresented, nonactively litigating claimants.

The problem, the issue we have, and again, I'll always fall back, Your Honor, when I'm appearing before you, the RKS claimants are most interested in moving forward with the with well-defined procedures that are in place efficiently, without delay, and expeditiously. We've heard a lot of questions raised here, and we raised plenty in our papers. One I haven't heard today is if they're answering these objections on behalf of claimants who didn't amend their claims, are they able to remove the reference for those claims when the Ninth Circuit comes down with its decision and suddenly PERA changes its mind about litigation strategy here. Right.

And what I think is a concern for us is that if there's an ill-defined lead plaintiff role and moniker put on PERA here and they're able to do things that aren't expressly allowed to them through this process, there's going to be

litigation about that. They're going to be binding people who may not want to be bound. They might make litigation decisions that people disagree with.

We think the best way to do this, if there is going to be a lead plaintiff designation, is to go through and finish the ADR procedures and sufficiency objections, as have already been enshrined in the Court's orders, and at that point a lead-plaintiff-type role for PERA might be helpful to coordinate discovery.

THE COURT: Okay. But Mr. Catalina, let's follow up on that just for a moment. You repeated today something that you said before. You believe and RKS believes we should be moving more quickly on the sufficiency objections. And I have to say that in thinking about the discovery issue, which I'm going to announce here in a few minutes, is that, well, okay, what happens if I overrule the sufficiency objections?

So just by my calculation, those matters will be submitted to me for decision if we're on schedule in May. So let's assume in May, I overrule the sufficiency objections in in whole or in part. Then what? Do I then allow Mr. Etkin to be lead interim counsel?

MR. CATALINA: Well --

THE COURT: In other words, what's different if we get past this wave of sufficiency objections and there's still some claimants still standing?

MR. CATALINA: Well, what they --

THE COURT: It's the same problem, isn't it? Isn't it the same problem?

MR. CATALINA: No. What's different is that at that point, now the Court has the case management issue that it's raised in the past, right --

THE COURT: Right. Right.

MR. CATALINA: -- that there's going to be some number of claims. And by the way, that number is reducing all the time. And I think after a decision, once parties have a better understanding of the strengths and weaknesses of their case and what remains, there's likely to be more settlement at that point that --

THE COURT: Of course. Of course. I understand.

MR. CATALINA: Yeah.

THE COURT: But that's still months away. That's months away.

MR. CATALINA: Certainly. I think at that point -- because, as Your Honor noted in the order, right, this is an undefined and unclear thing, this lead plaintiff designation, what I'm saying is that from a pure case management and practicality issue, as well as taking actions that bind claimants who have submitted claims, endowing them with powers now, PERA with powers now that are in any way ill-defined or that allows them to steer claims will be inefficient. It's

going to lead to more litigation that's going to slow down the sufficiency process.

As soon as that's done and we're in a place -- we're in a posture where we're setting discovery parameters and schedules and things like that, it actually will be more efficient, rather than having 600 claimants in the room, to have Mr. Etkin there to kind of represent their interests in crafting discovery parameters, schedule, and how we're going to litigate the claims going forward. So I think it actually helps the Court and helps move the process at that time. Whereas now, I don't think it does help move the process one bit. And in fact, it's only going to muddy the waters when we have this --

THE COURT: Okay.

MR. CATALINA: -- kind of ill-defined lead plaintiff in place.

THE COURT: Okay. Mr. Etkin, I think Mr. Slack was very animated and clear on his position, and he did cite with some confidence a number of cases, and some of which are local but none of which is technically binding. Do you know of a single case ever in your history where a district court has approved an interim class counsel when there's no other parallel proceeding or other counsel competing for the job? Is there a single one reported decision that would be like this one if I were to grant this motion?

MR. ETKIN: Well, Your Honor, I think we cite the two cases in our reply brief.

THE COURT: But just tell me what they hold. Do they have an -- well, one lawyer or law firm -- again, your cocounsel, but you know what I mean, one plaintiff group wanting to be lead counsel when there's no other competing plaintiff group competing for the job?

MR. ETKIN: Your Honor, I don't have --

THE COURT: Not a single one.

MR. ETKIN: I don't have those cases in front of me. I don't --

THE COURT: Well, in your experience, has it ever happened?

MR. ETKIN: In my experience, Your Honor, I have seen interim lead counsel appointed. Let's go to the advisory committee notes, Your Honor, that Mr. Slack referenced --

THE COURT: No, no. I'll tell you what. I don't want to go to the advisory notes. I want you to tell me what you're going to do otherwise if I were to grant this motion. You've said that for our pro se parties, not Mr. Catalina's clients and not Baupost, but you're going to reach out and offer to help them.

What else are you going to do? What else -- what other role do you play? Do you draft their opposition for them to the sufficiency objection?

MR. ETKIN: Well, the answer is yes. And the reason why I was citing the advisory committee notes, which we cited in our reply brief, is that they talk about what an interim class counsel will do. And we don't see our role as being any different than what they reference. They say, and I'm quoting --

THE COURT: Well, give me an -- give me an example.

MR. ETKIN: -- "Less counsel may be needed to engage in discovery." Now, I don't know what the Court's ruling is going to be on the discovery situation, but if the Court rules that the parties are entitled to discovery in advance of responding to the sufficiency objections, we would certainly participate in that with an interim class counsel role. They talk about motion practice. And they talk about (indiscernible).

THE COURT: Mr. Etkin. Mr. Etkin, I'm going to -- I'm going to -- this is called a spoiler alert. In about five minutes, I'm going to announce that I'm not going to allow any discovery, and I'll explain why. And unfortunately for you, your client and Baupost are really the respondents on that ruling.

But we've already got in place a very, very well established procedure for what happens between now and the sufficiency motion ruling. So what else is there for you to do? In other words, I don't think it's --

MR. ETKIN: If there is --

THE COURT: -- I think it's a little unseemly for me to suggest that you can go out and beat the bushes and hustle up clients. You can do it on your own if you want, but I don't believe I should give you an imprimatur to do that with the label of interim class counsel. I mean, you're free to -- you're free to call up these people if you want. I'm not going to tell you you can't do that. But what else are you going to do?

MR. ETKIN: That's not our role, Your Honor.

THE COURT: Okay. But what else are you going to do?

MR. ETKIN: Others may have done that, but that's not our role (indiscernible).

THE COURT: Mr. Etkin, I'm not suggesting that your guilt by association. What I'm suggesting is that I don't think, with the kind of comments that Mr. Slack made, that handing you a label that says I am now the official interim class counsel is appropriate if at the same time there's nothing for you to do.

So my question again is if you are not -- we have a very, very elaborate process in place to flush out the deficiencies or insufficiencies of the claims. And I suspect, despite Mr. Slack's advocacy, that some are likely to survive. And so what do you do with Mr. X or Ms. Y if I tell you there's not going to be any discovery and I've already said you don't

have standing to represent their interests individually? What else is there to do as interim class counsel?

MR. ETKIN: Well, Your Honor, the primary thing and the thing that I started with is opposing the sufficiency objections on behalf of putative class members.

THE COURT: On behalf of their claimant? In other words, you're going to advocate as advocate for them as claimants?

MR. ETKIN: That's right.

THE COURT: Okay.

MR. ETKIN: That's right, Your Honor.

THE COURT: So --

MR. ETKIN: That's all it --

THE COURT: -- it's probably easy for you to do it for every claimant that has adopted the PERA third amended complaint. But what about somebody else that just is on his own? You're going to take over that person's position?

MR. ETKIN: Well, I would hesitate to refer to it as taking over their position. I would rather refer to it as taking on a role of advocating on their behalf, since they are putative class members. And none of this is about class certification. That's down the road. We all know that.

THE COURT: I know. I know.

MR. ETKIN: But right now, all of these claimants, unrepresented claimants, are facing sufficiency objections

which effectively say that you don't have a claim. You don't have a claim on the merits. You should go home.

When you look at some of these pro se papers that have been filed, it kind of pulls back the curtain a little bit on what's been going on between the debtors and some of these individuals, where the debtors are saying that they have no claims, that their claims are subject to being thrown out, and here's a hundred dollars. Some of these people aren't accepting that. And frankly, the fire victims didn't accept that when on the basis of the same operative facts as these claims that are asserted as securities claims where they settled for over a hundred million dollars. I'm sure Mr. Catalina doesn't think these claims are --

THE COURT: That's not a very good analogy, frankly, no.

MR. ETKIN: Well, Your Honor, respectfully, I think it -- the their claims are based upon the same set of operative facts.

THE COURT: Some of the best tort lawyers in the West represented the fire victims, and maybe the fire victims didn't think they got enough. But in my experience, the results were much more appropriate and substantial. And it had nothing to do with the securities fraud claims that don't have anything to do with -- aren't analogous.

MR. ETKIN: If I may -- if I may, those weren't claims

asserted in connection with the horrendous losses that these people suffered. Those were claims, derivative claims, breach of fiduciary duty claims, mismanagement claims that were assigned to the fire victims trust and that were asserted in connection with a separate piece of litigation.

THE COURT: Oh, you were referring to the -- I thought you were referring to the overall tort --

MR. ETKIN: Oh, no, no, no.

THE COURT: The overall tort settlement.

MR. ETKIN: No, no, no, no.

THE COURT: Okay. Fair enough.

MR. ETKIN: I apologize, Your Honor. I apologize --

THE COURT: No, but I stand corrected.

MR. ETKIN: -- if I was unclear.

THE COURT: Okay. But again, all right. One more time. And what is the -- it sounds to me like Mr. Slack may be right. What's you're doing is you're trying to persuade me to put this interim class counsel label on you, you, again, not personally, and that's a way to get around my ruling that you didn't have standing to act as claimants and the individual claimants' counsel; am I correct? Is that --

MR. ETKIN: There's a very important distinction between those rulings and these sufficiency objections. For example, the last ruling involved a situation where we took a position as it relates to those claimants who never responded

to a settlement offer and that their claims were expunged as a result. We're not looking to take -- the Court was clear. We're not looking to get involved in situations like that. Also, there may be some objections that some of these claimants, by virtue of positions they took in the Chapter 11, that they effectively released their claims.

We're not looking to get involved in that. This is solely with respect to the sufficiency objections, which challenge the bona fides of the underlying securities claims. Every claimant is asserting those claims. Every claimant. They're not in a position --

THE COURT: Okay. So --

MR. ETKIN: They're not in a good position. So if those claims --

THE COURT: So the way the way you --

MR. ETKIN: If those claims are (indiscernible) --

THE COURT: I presume the way you get around a -- I assume the way you get around a sufficiency objection is you try to amend your claim.

MR. ETKIN: Not necessarily.

THE COURT: No? Okay.

MR. ETKIN: Not necessarily.

THE COURT: All right.

MR. ETKIN: We intend to file papers, and I think that that Mr. Catalina and I will probably look at some of the same

issues and make some of the same arguments. But what we're looking to do is challenge the debtors' ability to get these claims thrown out on the merits because they haven't asserted viable securities claims. And that's an issue that runs across the board. And that's the issue that we're looking to get involved in as interim class counsel to make sure -- to make sure that each of these individuals that are not represented by counsel have an appropriate say in what happens to the merits of their claims. Not more complicated than that, Your Honor.

THE COURT: Okay.

MR. ETKIN: And based upon the Court's indication of their ruling on discovery -- the ruling on discovery, we're going to have to do that without the benefit of further discovery. And if (indiscernible) --

THE COURT: I know, which is what gets me back to my question I'm not sure what you can do.

All right. Gentlemen, I'm on running on a tight schedule. And I --

MR. SLACK: Your Honor, I know you're on a tight schedule. Give me --

THE COURT: One minute.

MR. SLACK: -- give me. Thank you. That's all I need, Your Honor.

THE COURT: One minute. One minute. One minute.

MR. SLACK: I just want to -- I want to answer the

question you asked Mr. Etkin that he didn't answer, which is he said he had cases. Well, I'm going to tell you what his three cases under 23(g)(3) say. He cited the Schneider case. There, there were two separate class actions filed, and counsel in each of those actions was vying for the lead class plaintiff. That's the Schneider. Okay.

The second one was Wachovia. The Wachovia case, there were multiple counsel seeking to be class counsel of an ERISA class action. Thus, they had the same issue. They had multiple counsel vying in that case.

And then they cite the Foreign 1 Company (phonetic) case. In there, they were dealing with multiple counsel with different cases vying to be class counsel. And there, the court even said specifically based on the Manual For Complex Litigation that the interim counsel was based on the fact that there were a number of overlapping, duplicative, and competing suits present and that there were a number of lawyers competing for the class counsel appointment.

So I just wanted to answer that, that all of the cases under 23(g)(3) that PERA cites were, in fact, counsel competing --

THE COURT: Okay. Okay.

MR. SLACK: -- or competing cases.

THE COURT: Okay. Though it sounds to --

MR. SLACK: The second thing --

THE COURT: Well, what I'm saying --

MR. SLACK: Yeah. I just going --

THE COURT: -- is it just sounds to me like -- oh, go ahead. Go ahead.

MR. SLACK: I was just going to say that the second piece of this, of course, is that there's nothing different between the sufficiency objections from people. And let's just be clear. There were folks who had the opportunity to adopt PERA or adopt RKS or file an amendment, and they didn't do that. So we're not talking about Mr. Etkin coming in and dealing with his own complaint or saying that his own complaint is valid. Nobody is denying that he can go and say that and we're not going to be -- we're not going to be relitigating that with respect to other people that adopted his complaint.

But for the people who didn't, there's no difference between PERA trying to come into those where there are no allegations, at least according to us, and any other of the substantive, merits-based omnibus objections that we made. In fact, the first one, when Your Honor denied standing to PERA, was a substantive one that said people didn't have trades. They traded both bought and sold before the first record of disclosure that's on the merits. And this Court correctly said PERA doesn't have standing, even though it was merits based.

So Your Honor, those were the two points I wanted to leave you with. And I appreciate the opportunity. And we're

happy to file a pleading, if it would be helpful to the Court.

THE COURT: What I want -- well, I'll hold the matter under advisement for a very short period of time. I want you, Mr. Slack, to file a -- just file a document that gives full cites. I mean, these string cites of unreported cases sometimes have so many numbers in them, I can't keep up with them so I want just the cite of the cases that you rely on that you ran through and include in the same filing the three cases that you believe that Mr. Etkin wasn't able to rely on and I have Mr. Etkin's brief, but to just --

MR. SLACK: Yeah.

THE COURT: -- see them all in one place.

And Mr. Etkin, if --

MR. ETKIN: Your Honor --

THE COURT: -- if you --

MR. ETKIN: -- out of fair --

THE COURT: I was going to say -- I was going to say, if you have other authority -- what?

MR. ETKIN: I'm sorry.

THE COURT: What do you want to say?

MR. ETKIN: I was just going to say, out of fairness, since these are cites that Mr. Slack ran through earlier that don't appear in any of the papers, that we should have an opportunity to provide supplemental briefing as well.

THE COURT: I don't want -- I don't want briefing to

briefing this case. I have to move quickly on this.

MR. ETKIN: Supplemental authority, Your Honor.

THE COURT: So okay. Mr. Slack, can you file something by Friday?

MR. SLACK: Sure. I mean, if -- look, it seems to me that both sides can file something by Friday simultaneously and you'll have whatever because --

THE COURT: No, I was going -- I asked if you could do it on Friday.

MR. SLACK: Yeah, we can. No problem.

THE COURT: I don't need argument. Just say here are the cites that -- the cases that I'm citing.

Mr. Etkin, you can file any other citations without authority on Monday.

MR. ETKIN: Okay. Thank you.

THE COURT: In other words, and you don't have to refile something that lists the very cases that Mr. Slack -- I just, it's not that I don't like listening to your arguments. It's that I want to -- and I'm not going to repeat my frustration, but my frustration is to have to make a decision on a simple sentence in a plain Rule and get into this long discussion that you experts know about that I had no way of knowing about.

So if I take a look at these cases, I'll see what my colleagues on the bench have said and decide whether I should

do it. But that's where we'll stand. Submitted on the matter. So thank you all for your time. Now, I'm going to --

MR. SLACK: Thank you, Your Honor.

THE COURT: I'm going to offend some other counsel by making him wait a little bit longer because I'm going to go immediately to what I promised you is a ruling.

So Ms. Parada, for calendaring purposes, I'm going to treat the PERA motion as submitted. And I'm going to, for the docketing purposes, turn immediately to the oral ruling on the discovery issue. And so I don't think we need to have other people appearing and stating their appearance because I'm not really asking for appearances. So I'm just going to announce my ruling.

THE CLERK: Yes, Your Honor.

THE COURT: So the issue that all counsel are familiar with is the discovery requested specifically by PERA and also by Baupost pending resolution of the sufficiency motions that were filed by PG&E and challenging the principal claims of the securities claimants. And RKS is also -- in that briefing schedule are some of the former officers through their counsel. RKS joins PG&E, as do those other officers. So I'm just, I'm not (audio interference) going to talk about RKS position that there should not be discovery and PERA and Baupost position to the contrary.

And I start with an analysis that is not new to anyone

that's seen me or been before many bankruptcy courts, and that is that an objection to (audio interference) --

MR. ETKIN: Your Honor, we're having trouble --

THE CLERK: Excuse me, Your Honor.

THE COURT: -- is analogous -- analogous, not -- yes.

Yes, Ms. Parada.

THE CLERK: Your Honor, your audio. We're having trouble hearing you. It's cutting in and out.

THE COURT: Oh, wonderful. Okay. Hold on. Let's see if I can -- what I can do about this.

Is that any different if I speaking now, Ms. Parada?

THE CLERK: It sounds better now, Your Honor.

THE COURT: Okay. Okay. I'm saying that there's the analogy, and this comes up, of course, because there are numerous claims on file in the PG&E case and PG&E has objected to the claim and now is challenging under the so-called sufficiency objections.

The proof of claim is analogous to a complaint. And a complaint is governed by the Federal Rules of Civil Procedure. A bankruptcy claim is governed by the Bankruptcy Rules. But the point is that there's a lot of similarity. And when a claim is filed, it's like a complaint. When an objection to claim is filed, it's analogous to a motion to dismiss or an answer. And certainly, the Supreme Court's teaching from Iqbal and other authorities on plausibility are well established law,

as the notion that in a complaint, the allegations of the complaint are deemed to be true unless challenged under some other theory. And same is true with a proof of claim. It's deemed allowed and taken to be true unless it's challenged by the objection process.

And so a PSLRA, which we've had this endless discussion on whether it applies or doesn't apply, it says that there's to be no discovery pending a sufficiency determination. Rule 12(b)(6) in the traditional setting, I don't believe, has a similar silencing effect in terms of discovery, but clearly it's treated in the same way. A 12(b)(6) motion is treated as though the complaint is deemed to be true, and a motion to dismiss challenges the sufficiency and the -- of plausibility of the allegations.

So here, regardless of any other choice of law, we have the July 2023 order that was well hammered out through efforts by the debtor, particularly RKS and Baupost. To a lesser degree by PERA, but nevertheless, PERA was aware of it. And in any event, it is in place, and it says no discovery pending these sufficiency determinations.

Some of the opposition here from Baupost and PERA suggests that this is governed by Rule -- we're governed here by Rule 9014. Well, we are governed by 9014, but 9014, in turn, incorporates and can incorporate all the other Federal Rules. And Rule 12 is certainly one of those other Federal

Rules that, although not incorporated specifically in the language of 9014, is very much incorporatable and has been the source for the way, certainly, the July 23rd order is consistent Rule 12(b).

And more importantly and locally, the claims objection process are governed by Bankruptcy Local Rule 3007-1(b). And 3007-1(b) deals with what happens on a first hearing on a claims objection. And the Rule makes clear that if there are facts to be -- unresolved facts to be decided, that cannot be disposed of at the preliminary hearing. But if there are questions of law that can be dispositive, they can be disposed of at that preliminary hearing. And whereas there is Rule is silent on whether there can be discovery pending a claims objection, in practice, there should not be if, as a matter of law, the proof of claim isn't plausible, just like a complaint should be disposed of if it is not plausible as a matter of law.

So here, on the Court's -- the Court assumes and will assume the facts as set forth by the claimants PERA, Baupost, and RKS are true for purposes of the sufficiency objection. And again, I won't repeat the ground rules that we're all familiar with with motions to dismiss.

So what I conclude from all that is there's simply no facts to be decided at that preliminary hearing if the law compels the outcome that the objector seeks. And so PG&E has

filed very voluminous papers in support of its sufficiency objections, but to the extent that those papers, particularly the voluminous documents they want me to take notice of, it's of no consequence to take notice of things that are factual determinations when the only test that I believe is relevant is what I said, the sufficiency of the claims themselves. So I haven't taken the time to study the details of PG&E's submissions or at all in detail. The point is, I don't know why I would consider disputed facts when the only thing I need to consider is the sufficiency, therefore, the underlying plausibility, of what is alleged in the respective proofs of claim.

And so that's a long way of saying that -- not that I won't consider what PG&E filed in opposition, but I will say that whatever facts that are in dispute that PERA and Baupost may want to rebut, it's a waste of time to try to rebut them because that's not the inquiry. PERA and Baupost and RKS, their claims will survive the sufficiency on their own face, on their strength of themselves, not on the weakness of what they believe exists in PG&E's defenses. Those will be tested after the sufficiency objections are favorably disposed of in favor of the claimants and will not be at all relevant if the sufficiency objections are sustained.

So at summary judgment or trial or somewhere in the future, those facts will be relevant. This is a -- take this

all together, there's no appropriate purpose for discovery, pending the sufficiency objections determination, and thus the collective requests by PERA and Baupost must be denied. Discovery stay will remain in effect for all of those reasons.

So gentlemen, with that ruling, I don't know if I need to issue a formal order. I guess I perhaps will issue a simple order that says, for the reasons stated in the oral ruling, there will be no discovery by the objectors pending the sufficiency objections. And I will then look forward to the filings from Mr. Etkin and Mr. Slack and try to issue a ruling as early as the middle of next week on the interim class representative question, again, without a lot of detail. I look to see if there's any -- well, I'll leave it at that.

So thank you for your time. Anybody have any questions?

Nothing. Okay. Mr. Slack.

MR. SLACK: Thank you, Your Honor.

MR. ETKIN: Just the timing concern, Your Honor.

THE COURT: Yes, sir.

MR. ETKIN: Given what we've discussed today and what, at least, we feel our role would be as interim counsel with respect to challenging the sufficiency objections, the objections and the -- the objections and the response deadlines and the hearing dates are scattered, as the Court pointed out. The dates for us, for the RKS clients, are a bit later. I'm

just concerned that given the role that we think we should play and want to play with respect dealing with these sufficiency objections across the board, as to those that are the subject of them, that their time to respond is going to come and go. A lot of these unrepresented people may not file anything. And we've gotten a lot of phone calls from folks who are asking us what to do; can we rely on the opposition that you're filing.

So I just have a concern for these folks that their time is going to come and go, something that obviously the reorganized debtors would look forward to. We, on the other hand, want to make sure that -- and that's been our stance throughout -- that at least these folks have the benefit of somebody filing something substantive on their behalf.

THE COURT: Mr. Etkin, I'll repeat something. It's none of my business if you sign up Mr. X or Mr. Y as additional clients tomorrow. But I'm not going to empower you with a label that perhaps is inappropriate. And if I grant your motion, I am not -- you've got to understand, and I don't -- well, I'll tell you what.

(Audio interference) motion, I guess I have to say there may be consequences. If I deny your motion, I'm still not in a position with any authority to tell you you can't take on the representation of a particular individual. Whether you can represent an individual while at the same time you represent PERA, now this is your business and not my business.

I'm not going to disqualify you. If someone believes that you're doing so disqualifies you, they'll have to bring an appropriate motion.

So to the extent that you're caring and thoughtful about these pro se individuals, I compliment you. But I can't empower you in a manner that's inappropriate. I can just say, do what you need to do. And I can't tell you to give legal advice to these people or give you some sort of a get out of jail free card that says you now have -- you've got some form of official authority because at the moment, you don't.

So that's the best I can say. But that being said, I am mindful that things need to move more quickly if I'm persuaded that you should be allowed to have that label. And that's why I move forward quickly. That's why no more briefing. That's why just let me get the kind of additional help that I might have expected earlier on the briefing when I now know what Mr. Slack and Mr. Catalina and Mr. Hamilton think about what 23(g)(3) is supposed to be all about.

So I'll leave it at that. I'm not going to beat this to death. Thank you for your time, gentlemen. Have a good weekend. Good day.

IN UNISON: Thank you, Your Honor.

THE COURT: All right. All right. Okay. Has Mr. Jacobson gone to lunch?

THE CLERK: No. I will bring in Mr. Jacobson now,

Your Honor. And Mr. Lamb, I believe, is joining.

THE COURT: All right. Mr. Jacobson, I'm sorry about this. Mr. Lamb owes you something. A lunch, maybe.

MR. LAMB: I apologize, Your Honor. I had serious technical difficulties.

THE COURT: Okay. Mr. Jacobson, just say something so I know you're on the line.

MR. JACOBSON: I'm here.

THE COURT: Okay. Well, again, I apologize for the inconvenience. But so Mr. Lamb, looks like you have a busy trial schedule, but let me tell you, why can't I suggest a two-day trial in person in court, not Zoom, but no more than two-day trial in late June? It seems to fit your trial schedule. Any reason why we couldn't do that?

MR. LAMB: Well, Your Honor, I think that based on what I've seen from submissions from Mr. Jacobson, I think that two days is not going to be sufficient. I think it's probably going to be more along the lines of a eight-to-ten-day trial. I understand that it's going to be a bench trial, but I think it will take some time.

We have looked through what counsel has proposed regarding dates, and I'll be prepared, probably today or tomorrow. There's four of the dates that we can confirm. I'm still trying to figure out a couple of dates.

There's a number of issues, though, relating to what I

believe are requests for discovery, both depositions and written, that is past the date that is closed based on docket order number 13921 that was issued by the Court, where written discovery was closed on October 6th and percipient depositions were closed on October 15th. And we just heard about that two days ago. So we're willing to meet-and-confer about that. But I think that that's going to take some time.

Plus, I would think it would be advisable for us to take some time once we can get these depositions of experts done to review those matters and sit down and have, hopefully, a meaningful mediation that will hopefully avoid the requirement for your involvement in that trial, Your Honor. So that's --

THE COURT: I thought the -- I thought the mediator was available in April.

MR. LAMB: We don't have a date yet. I've kept trying to get dates, and we don't have a date yet. I mean, every time I've asked, we've talked about it. There was a date that was proposed by me, but it's way early. It's before any of the depositions, and it's right in the middle of basically a vacation I'm taking the following week where I'm out of the Country. So I couldn't do that.

And I haven't heard back yet from Mr. Jacobson about other dates. But hopefully, it would be sometime -- I think we can probably get the depositions done of the experts,

hopefully, in April. I think the last date that Mr. Jacobson proposed was April 12th. Like I said, we still have a couple of people that we don't have dates yet. I'm trying to get that. Hopefully, I can get that in the next couple of days.

And in regards to the other issues, there are a number of individuals. They listed Mr. Petree, Mr. Salguero, Mr. Cortez. These are percipient. They're not experts. So I don't see that that would be called for under the current stipulation and order entered by the Court, but I'm willing to meet-and-confer about that. Like I said, we just heard about that a couple days ago, Your Honor.

THE COURT: Well, we're jumping around.

Mr. Jacobson, didn't you -- where did I see -- you have agreed on a mediator who I thought Mr. Bening was available in April; is that incorrect?

MR. JACOBSON: No, that is correct. And I proposed a discovery deposition schedule that concludes in mid-April. And Mr. Bening is available throughout the month of April and May. He has many days in the second half of April. And the entire month of June is open for all counsel. So we can complete the depositions and the mediation by 1st of May or early May. And then we have the entire month of June for trial.

THE COURT: Well, we're not going to have a trial if you settle, obviously, but --

MR. JACOBSON: Right.

MR. LAMB: If I may, Your Honor.

THE COURT: Yeah, please.

MR. LAMB: The problem with that, though, is we have to then have availability of individuals in June for that trial. And I know that there are some individuals now that are not going to be available if we wind up going to a trial. And we have --

THE COURT: Okay. Fair enough. Hold on.

MR. LAMB: We have issues with --

THE COURT: Mr. Lamb, slow down. Slow down.

Mr. Jacobson, what do you think is a trial time estimate?

MR. JACOBSON: I think five days on the outside.

THE COURT: What are the issues besides the height of the wire?

MR. JACOBSON: There's just a lot of detail packed into it.

THE COURT: But what kind of facts have to be proven? I mean, gentlemen, I got to tell you -- in fact, now I'm read that maybe Mr. Raines had the wire lower than it was. What is there to testify and prove at trial, other than the height of the wire and the economic impact of it?

MR. JACOBSON: Those are issues, and there are simply technical details about it. Mr. Raines has a very long declaration about all kinds of scans and measurements and such.

And we just need the normal depositions and trial on those issues.

THE COURT: I know. I understand you need the depositions. You think I'm going to have a trial where I'm going to have competing witnesses tell me the height of the wire at a given point?

MR. JACOBSON: That would be a disputed fact, yes.

THE COURT: And so one witness says it's twelve feet and six inches and the other witness says it's fourteen feet and three inches and I'm going to make a fact determination of that?

MR. JACOBSON: Well, I think I --

THE COURT: I guess, I got to tell you, I don't understand why this doesn't all translate to economic impact and an expert saying, with the wires the way they are, the property suffered a value decrease of X dollars. And the other witness say, no, it was really Y dollars.

I mean, I'm not going to make a decision today. But the notion that why this isn't done by competing experts who submit expert reports and are subject to cross-examination, I can't imagine that beyond that, what is there to try. So I'll keep an open mind about how much time to set for trial, but I still instinctively am mystified that it would take even two days with experts. But I won't prejudge that.

MR. JACOBSON: Well, my comment was five days on the

outside after I heard an eight-day estimate or whatever from opposing counsel. Particularly with your standing order with respect to experts and declarations and cross-examination and such, five days is an outside. I would say, three, four days.

THE COURT: Well, I'm not trying to negotiate this with you now. I'm just saying that you need to be prepared to persuade me what we do, and we'll do it. And we'll do it live in 450 Golden Gate Avenue.

But the question is, what else is there to do today. And I accept that Mr. Lamb has a vacation schedule, and I respect that. And he's got other trial commitments. And you gentlemen can work out things for mutual adjustments of deadlines. And if not, I'll make my decision on it.

But I think for now, the only thing I would do is perhaps just pin down another status conference and let things shake out and tell you to get on. Get it resolved. And not tell you when to mediate and who to select and who to depose and who not to depose.

But I will say, when it comes time to pin down the trial, I'm going to require each side to give me a summary of what each witness is going to say, a nonexpert witness. I mean, if you tell me that Mr. So-and-so is your expert on the valuation, then I'll just make you agree on when that expert's report will be available. And we'll follow the procedure of the report being filed and the expert starting with cross-

examination. And same with the other expert or two experts or three experts. But we don't -- but not percipient witnesses.

Yes, Mr. Jacobson.

MR. JACOBSON: This has been pending a long time. We have a very discreet deposition schedule. We have the entire month of June open. And if we -- it's appropriate at this point to have a trial date. And the trial date -- the existence of the trial date influences the mediation. It's not just we're up against a status conference. There is a benefit to having the trial date. Things don't just keep getting postponed. And if we need to change the trial date for some reason, that's always an option. We would just like to have a trial date during the month --

THE COURT: Okay.

MR. JACOBSON: -- everybody is available and discovery's been completed.

THE COURT: Mr. Lamb, any --

MR. LAMB: And I know that that date would be September. And I don't see what the major issue is. I don't see having a problem with a further status conference. We're going to meet-and-confer regarding things. But I just, I think that that's overly ambitious in June because I have to have schedules with people that are going to be able to appear at trial. And I know that we can get that scheduled by June.

So if you want a firm date versus a further status

conference, that's why I would ask for September.

THE COURT: So it's January now, and January now --

MR. LAMB: It's January.

THE COURT: And so January 24th, you have to -- I have to know when your witness is available in September, rather than tell you that the witness better be available in June? I'm sorry. That's not going to fly.

MR. LAMB: Your Honor, I'm not sure what witnesses we're going to have yet because we haven't done all these depositions and there's a number of --

THE COURT: I know.

MR. LAMB: -- these percipient witnesses that we have to meet-and-confer about because I think that that's been closed already.

THE COURT: But I just got through telling you, I don't know what the hell some percipient witness is going to do. What do you think the percipient witness is going to testify to?

MR. LAMB: I didn't ask for it, Your Honor. These were asked for by Mr. Jacobson.

THE COURT: Well, how about any -- how about any witnesses you're going to call?

MR. LAMB: How many witnesses am I going to call?

THE COURT: No, no, no, no. Do you have any percipient witnesses that you intend to call?

MR. LAMB: Yes.

THE COURT: And what are they going to testify to?

MR. LAMB: They're going to testify about the circumstances relating to the line height and what was observed then and what Mr. Shahmirza is claiming now and whether or not there were --

THE COURT: What was observed then? Well, Mr. Lamb, what was observed then isn't relevant. What is relevant, seems to me, is the situation now. I mean, I -- really --

MR. LAMB: Or I think it's -- I think it's --

THE COURT: -- maybe we should have a --

MR. LAMB: -- both relevant.

THE COURT: -- maybe we should have a site inspection. I mean, I can get out there with my tape measure, if I don't get electrocuted, and figure out how high the wire is.

MR. JACOBSON: Judge, this is a status conference for scheduling. And we're talking about June, which is five months away. And we're talking about a handful of depositions and a mediation. That's a huge amount of time from now till June. And asking for September --

THE COURT: Right.

MR. JACOBSON: -- just bespeaks an objective, a strategy of trying to delay this.

THE COURT: Mr. Lamb, I have to agree with him on this point. I'll tell you what. I'm still skeptical on why we even

need anywhere near, like, five days. So I'm going to give you a three-day -- a three-day block for an in-person trial in late June. And the June is designed to accommodate Mr. Lamb's competing trial schedule. He's busy, and compliment to him. And he's entitled -- and he's got a vacation plan. And we'll take a -- we'll have a status conference in two or three months prior to that time to check in with it.

So Ms. Parada, three days in the second half of June.

THE CLERK: How is June 24th, 25th, and 26th?

THE COURT: Sold. Mr. Jacobson, any problem with that?

MR. JACOBSON: Agreed.

THE COURT: Mr. Lamb?

MR. LAMB: Well, Your Honor --

THE COURT: I understand you don't really agree, but I mean, are those dates available?

MR. LAMB: They could be available for me, but I have to make sure that there's witness availability.

THE COURT: Well, we have a tail wagging the dog here. This is the Court picking a trial with principal counsel.

MR. LAMB: Yes.

THE COURT: And if you can't make a witness available, we'll figure out some other way. If there is a absolute critical witness that's going to be having heart surgery or be in another country, that's one thing. And if there's somebody

that just, there's an inconvenient time for a percipient witness, get a different percipient witness. And I will have a -- and you have plenty of time to have experts available and have their reports.

So I'm going to -- I'm going to pick mid-April for a further status conference. Separately set. Ms. Parada, it can be on the PG&E calendar or separately.

THE CLERK: April 23rd at 10 o'clock.

THE COURT: That time and date convenient for you, gentlemen?

MR. LAMB: I'm scheduled to be in a trial during that week.

THE COURT: Are you on a trial that day or not?

MR. LAMB: Yes. Yes.

THE COURT: Okay. So how about you want a week earlier? Is that right? You can (indiscernible) by Zoom. We'll do this by Zoom.

MR. LAMB: Okay. That'd be fine, Your Honor.

THE COURT: But I want to accommodate you.

MR. LAMB: Sure.

THE COURT: So Ms. Parada, is the 16th available?

THE CLERK: Yes, Your Honor.

THE COURT: Mr. Jacobson, that works?

MR. LAMB: The 15th is the -- the 16th is when the trial starts, so actually, the 15th would be better.

THE COURT: Is that available, Ms. Parada?

THE CLERK: Yes, Your Honor, at 10 o'clock.

THE COURT: Mr. Jacobson, that work for you?

MR. JACOBSON: Yes.

THE COURT: Okay. Gentlemen, we have a status conference on April 15th at 10 o'clock to discuss all the things we've talked about, whether there's any open discovery issues, whether you've agreed on deadlines for experts reports and so on. And for now, I'm penciling in, but marking on the calendar, a three-day trial in San Francisco in person on June 24.

I won't issue a trial scheduling order yet. I'll wait until after the April status conference. But there's no reason, unless you all tell me otherwise, to not follow my normal trial schedule with briefs ahead of time and experts reports and all that stuff. But both of you know what that is, and maybe you'll have all worked it -- it all worked out.

So it seems to me that I'm available between now and then if there's a dispute that isn't resolved about whether you renew nonexpert witnesses, whether the experts get deposed, whether Mr. Shahmirza gets deposed. Yeah, everything that that you've all been talking about.

And when we have the status conference on April 15th, we'll talk about actual trial time and who the witnesses are, and you should anticipate making a demonstration then or

promptly after that about who your witnesses will be and why they will be necessary and what they'll talk about so we can decide whether that seems necessary. And I will promise you that we'll have the trial. And if the plaintiff, particularly the claimant, or either side, but particularly the claimant here, needs more time than three days, we'll figure out a way to bifurcate it and make it work.

But Mr. Jacobson, you have your request. You have a firm trial date. And the best thing you all can do is make sure it never happens because you got the case resolved on a mediated result. Okay.

MR. JACOBSON: I have a question. Is your normal pre-trial order applicable here?

THE COURT: Yeah, but I just wasn't going to issue it until the status conference.

MR. JACOBSON: Okay.

THE COURT: Yeah, that's what I'm saying. I mean, my pre-trial for me is it's briefs, whatever, ten or whatever days to prior it is and all the other stuff. I can't remember it, but there's plenty of time for it. Okay.

Mr. Lamb, any questions?

MR. LAMB: No, Your Honor.

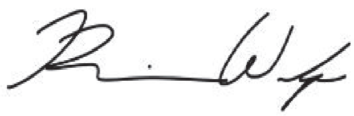
THE COURT: Okay. Thank you. Again, sorry about the delay. And good luck to make some progress in this case.

(Whereupon these proceedings were concluded at 11:37 AM)

I N D E X

C E R T I F I C A T I O N

I, River Wolfe, certify that the foregoing transcript is a true and accurate record of the proceedings.



/s/ RIVER WOLFE, CDLT-265

eScribers
7227 N. 16th Street, Suite #207
Phoenix, AZ 85020

Date: January 25, 2024

EXHIBIT G

UNITED STATES DISTRICT COURT
CENTRAL DISTRICT OF CALIFORNIA

GLEN BARNES, Individually and On Behalf of All Others Similarly Situated, Plaintiff, vs. EDISON INTERNATIONAL, SOUTHERN CALIFORNIA EDISON COMPANY, PEDRO J. PIZARRO MARIA RIGATTI, KEVIN M. PAYNE, WILLIAM M. PETMECKY III, THEODORE F. CRAVER, JR., WILLIAM JAMES SCILACCI, SCE TRUST VI, CONNIE J. ERICKSON, J.P. MORGAN SECURITIES LLC, MORGAN STANLEY & CO. LLC, RBC CAPITAL MARKETS, LLC, WELLS FARGO SECURITIES, LLC, CITIGROUP GLOBAL MARKETS INC., MIZUHO SECURITIES USA LLC, MUFG SECURITIES AMERICAS INC., PNC CAPITAL MARKETS LLC, TD SECURITIES (USA) LLC, U.S. BANCORP INVESTMENTS, INC., ACADEMY SECURITIES, INC., C.L. KING & ASSOCIATES, INC., DREXEL HAMILTON, LLC, and SAMUEL A. RAMIREZ & COMPANY, INC., Defendants.	Case No.: 2:18-cv-09690-CBM-FFM **<u>CLASS ACTION</u>** Hon. Consuelo B. Marshall **CONSOLIDATED SECOND AMENDED CLASS ACTION COMPLAINT FOR VIOLATION OF FEDERAL SECURITIES LAWS** **JURY TRIAL DEMANDED**

TABLE OF CONTENTS

Lead Plaintiff Iron Workers Local 580 Joint Funds ("Lead Plaintiff") and additional named Plaintiff Irving Lichtman, on behalf of the Irving Lichtman Revocable Living Trust ("Litchtman") (collectively, "Plaintiffs"), individually and on behalf of all other persons similarly situated, by Plaintiffs' undersigned attorneys, for Plaintiffs' consolidated second amended complaint against Defendants, allege the following based upon personal knowledge as to Plaintiffs and Plaintiffs' own acts, and information and belief as to all other matters, based upon, *inter alia*, the investigation conducted by and through Plaintiffs' attorneys, which included, among other things, a review of the Defendants' public documents, conference calls and announcements made by Defendants, United States Securities and Exchange Commission ("SEC") filings, wire and press releases published by and regarding Edison International ("Edison") and Southern California Edison Company ("SCE"),[1] analysts' reports and advisories about the Company, and information readily obtainable on the Internet. Plaintiffs believe that substantial evidentiary support will exist for the allegations set forth herein after a reasonable opportunity for discovery.

NATURE OF THE ACTION

1. This is a federal securities class action brought on behalf of a "Class" consisting of all persons and entities, other than Defendants and their affiliates, who purchased Edison securities from February 23, 2016, through October 29, 2019, both dates inclusive, as well as all persons and entities, other than Defendants and their affiliates, who purchased Edison Securities pursuant or traceable to the Company's Trust Preference Securities Offering (the "Offering") pursuant to the registration statement dated June 14, 2017 and/or the prospectus dated June 19, 2017 (the "Offering Documents"). Plaintiffs seek to pursue remedies against Edison and certain

[1] SCE and Edison are collectively referenced herein as the "Company."

of its officers and directors, and certain underwriters for violations of the federal securities laws under the Securities Exchange Act of 1934 (the "Exchange Act") and/or the Securities Act of 1933 ("Securities Act").

2. In 2017 and 2018, two massive wildfires occurred within a single 12-month period as a result of Edison's failure to maintain its electrical infrastructure. The Thomas Fire, which burned over 280,000 acres and triggered mudslides that killed nearly two dozen people, children among them, was one of the ten most destructive fires in California history. The Woolsey Fire, which burned more than 96,000 acres and killed three people, is the largest fire in Los Angeles County history.

3. Prior to and during the Class Period, Edison and its SCE subsidiary acknowledged their duty – and publicly represented their ability – to assess and mitigate wildfire risks, as well as to monitor severe weather conditions that posed an increased risk of a wildfire. Edison repeatedly reassured investors of its alleged commitment to safety, dedication to infrastructure improvement, and wildfire mitigation efforts.

4. In the run-up to the Class Period, regulators demanded that Edison ramp up its pole inspections and repairs for overloaded and deteriorated poles. Instead, Edison rewrote its software for the express purpose of minimizing the number of inspections and repairs it would be required to complete.

5. During the Class Period, SCE received dozens of citations in electrical audits carried out by the California Public Utilities Commission ("CPUC") for, among other things, past-due work orders, exposed ground wires, interference with equipment by vegetation, and faulty pole-loading calculations.

6. CPUC's Safety and Enforcement Division ("SED") harshly criticized Edison in January 2017 for lacking a coherent approach to risk assessment, an area critical to wildfire prevention.

7. Edison raised $475 million in the Company's Offering of preferred stock during the Second Quarter of 2017, pursuant to a Registration Statement and a Prospectus which made material misrepresentations regarding the Company's safety record, dedication to infrastructure improvement, wildfire mitigation efforts, lack of any coherent approach to risk assessment, and citations and critical response by the CPUC and the SED.

The Thomas Fire

8. On December 4, 2017, sparks by SCE power lines came into contact during high winds at two separate ignition points which started the Thomas Fire. At the time, even though a "Red Flag Warning" had been issued by the National Weather Service in regard to a severe ongoing high-wind event, the SCE Defendants elected not to deactivate Edison's lines.[2]

9. The market understood that Edison had also caused the Thomas Fire, which began in Edison's territory.

10. Accordingly, Edison shares tumbled $10.26 – nearly 14% – between December 4, 2017 and December 5, 2017, eliminating more than $3 billion in market value.

11. After the market closed on December 11, 2017, SCE disclosed that "[t]he causes of the wildfires are being investigated by CAL FIRE… SCE believes the investigations now include the possible role of its facilities."

12. Following SCE's admission that it was being investigated by Cal Fire, other fire agencies and CPUC as the source of the fire, Edison's stock price fell another $4.40 per share, or approximately 6%, to close at $68.58 per share on

[2] Red Flag warnings issued by the National Weather Service identify time periods when conditions are ideal for wildfires.

December 12, 2017.

13. Despite SCE's knowing – no later than late December 2017 – that its equipment had caused the Thomas Fire, the SCE Defendants spent the next ten months telling investors and analysts that they had no direct knowledge of the Company's liability or the extent thereof.

14. Almost a year later – in late October 2018 – SCE belatedly acknowledged its equipment sparked one of the Thomas Fire ignition points.

15. Investigators also determined that SCE was, in fact, responsible for both fires, and found criminal violations – ***including involuntary manslaughter and reckless arson*** – on SCE's part.

The Woolsey Fire

16. On November 7, 2018, the National Weather Service "upgraded the current weather event to a Red Flag warning for Los Angeles County, including Malibu beginning Thursday, November 8, 2018 at 8:00 AM through Friday, November 9, 2018 at 8:00 PM. Coastal areas are expecting gusts around 35 MPH, with 50-70 MPH gusts predicted in the mountains."

17. Despite reassuring investors – and the general public – of their capability to do so during high-wind events, the SCE Defendants once again failed to deactivate Edison's lines.[3]

18. On November 8, 2018, the Woolsey Fire started in Southern California, and was not fully contained until November 21, 2018.

19. Between November 10 and 11, 2018, it was gradually revealed that SCE had filed an incident report with CPUC on the evening of November 8, stating that

[3] Indeed, SCE did not proactively deploy its then-existent public safety power shut off plan until June 2019.

there was an interruption to SCE's Big Rock 16 kV circuit near its Chatsworth substation just two minutes before the first report of a fire came in. The substation is located at the same location where the Woolsey Fire began.

20. On November 12, 2018, CPUC launched an investigation into SCE, in order to "assess the compliance of electrical facilities with applicable rules and regulations in fire-impacted areas."

21. Following the November 10-12 disclosures of the November 8, 2018 incident report and CPUC's announcement, Edison's stock price fell $7.44 per share, or more than 12%, to close at $53.56 per share on November 12, 2018. Over the following days, as the Woolsey Fire continued to burn, Edison International's stock price continued to fall, closing at $47.19 on November 15, 2018, a total drop of 32% from its price prior to CPUC's announcement.

22. On December 6, 2018, post-Class Period, SCE sent a letter to CPUC disclosing that Edison crews had discovered a guy wire, or a metal wire attached to the ground that supported the pole, in close proximity to a jumper, which connects power lines, on its Big Rock 16 kV circuit. The significance of this information is that the guy wire and jumper are likely to have contacted with each other or other Edison electrical equipment to start the blaze.

23. On August 30, 2019, the California Attorney General's Office was reported to be conducting a criminal investigation into the cause and origin of the Woolsey Fire.

24. On or about September 26, 2019, the California state court overseeing civil litigation associated with the Woolsey Fire ruled that a redacted version of the California Attorney General's investigative report on the fire could be produced to attorneys involved in the civil litigation, including attorneys for SCE, but not the general public. The court said that the full report would be released in April 2020.

25. On October 29, 2019, SCE disclosed that investigators had again determined that "electrical equipment owned and operated by SCE was the cause of the Woolsey Fire. Absent additional evidence, SCE believes that it is likely that its equipment was associated with the ignition of the Woolsey Fire."

26. Following SCE's admission of its involvement in causing the Woolsey Fire, Edison's stock price declined by $3.24 per share, or more than 5%, to close at $62.16 per share on October 30, 2019.

27. On November 13, 2019, SCE agreed to pay $360 million to twenty-three (23) public entities to settle legal claims in connection with the Thomas Fire and subsequent mudslide, as well as the Woolsey Fire.

28. Under California's "inverse condemnation" statute, which holds utilities legally responsible for fire damage if their equipment is deemed to be a cause, SCE stands to incur billions in liability for the Woolsey Fire. Where CPUC regulators determine that the utility "acted reasonably" to maintain its equipment, the costs can be passed onto ratepayers. But if negligence is established, the utility would have to shoulder the costs. SCE already stands to owe billions of dollars in connection with its role in the Thomas Fire.

29. Accordingly, the Company was motivated to conceal its misconduct in order to preserve its ability to seek ratepayer indemnification for wildfire damages.

30. Company was further motivated by its potential liability to avoid disclosing conduct that carried with it the high risk of investor flight and/or loss of market capitalization.

31. Upon the disclosure or materialization of the risk of Defendants' wrongful acts and omissions, and the resulting precipitous decline in the market value of the Company's securities, Plaintiffs and other Class members have suffered significant losses and damages.

JURISDICTION AND VENUE

32. The claims asserted herein arise under Sections 11, 12(a)(2) and 15 of the Securities Act, 15 U.S.C. §§ 77k, 77l, and 77o and under Sections 10(b) and 20(a) of the Exchange Act, 15 U.S.C. §§ 78j(b) and 78t(a), and SEC Rule 10b-5 promulgated thereunder by the SEC, 17 C.F.R. § 240.10b-5.

33. This Court has jurisdiction over the subject matter of this action pursuant to 28 U.S.C. § 1331, Section 27 of the Exchange Act, 15 U.S.C. § 78aa, and Section 22 of the Securities Act, 15 U.S.C. § 77v.

34. Venue is proper in this District pursuant to Section 27 of the Exchange Act, 15 U.S.C. § 78aa; Section 22 of the Securities Act, 15 U.S.C. § 77v; and 28 U.S.C. § 1391(b). Edison is headquartered in this District, Defendants conduct business in this District, and a significant portion of Defendants' actions took place within this District.

35. In connection with the acts alleged in this complaint, Defendants, directly or indirectly, used the means and instrumentalities of interstate commerce, including, but not limited to, the mails, interstate telephone communications, and the facilities of the national securities markets.

PARTIES

36. Lead Plaintiff, as set forth in its certification previously filed with the Court, which is incorporated herein, acquired Edison securities at artificially inflated prices during the Class Period and was damaged upon the revelation of the alleged corrective disclosures and/or materialization of known risks.

37. Additional named Plaintiff Litchtman purchased 14,000 shares of Edison Trust Preference Securities at $25 per share on June 19, 2017, and was damaged upon the revelation of the alleged corrective disclosures and/or materialization of known risks. Plaintiff Litchtman purchased his Edison shares directly in the Offering from

underwriters RBC Capital Markets, LLC and TD Securities (USA) LLC. The certification for Plaintiff Litchtman was previously submitted to the Court.

38. Defendant Edison is a California corporation with its principal executive offices located at 2244 Walnut Grove Avenue (P.O. Box 976), Rosemead, California 91770. Edison's common stock trades in an efficient market on the New York Stock Exchange under the ticker symbol "EIX."

39. Defendant SCE is a California corporation with its principal executive offices located at 2244 Walnut Grove Avenue (P.O. Box 976), Rosemead, California 91770. SCE's securities are traded in an efficient market on the NYSE American LLC (together with the New York Stock Exchange, "NYSE").

40. Defendant Theodore F. Craver, Jr. ("Craver") served as the Chief Executive Officer ("CEO") of Edison International from 2008 until his resignation, effective September 30, 2016.

41. Defendant Pedro J. Pizarro ("Pizarro") has served as the CEO of Edison International since October 2016. Prior to that, Defendant Pizarro served as President of Edison International from June 2016 to September 2016 and President of SCE from October 2014 to May 2016.

42. Defendant Maria Rigatti ("Rigatti") served as the Chief Financial Officer ("CFO") of Edison International since October 2016, and prior to her appointment as CFO of Edison international she served in the same capacity for SCE.

43. Defendant Kevin M. Payne ("Payne") served as President and CEO of SCE since June 2016, and is also a member of SCE's board of directors.

44. Defendant William M. Petmecky ("Petmecky") has served as Vice President, Chief Financial Officer and Controller of SCE since October 2016.

45. Defendant William James Scilacci ("Scilacci"), served as the Chief Financial Officer of Edison International until his resignation, effective September 30,

2016.

46. The Defendants referenced above in ¶¶40-45 are sometimes referred to herein collectively as the "Individual Defendants."

47. The Individual Defendants possessed the power and authority to control the contents of the Company's SEC filings, press releases, and other market communications. The Individual Defendants were provided with copies of the Company's SEC filings and press releases alleged herein to be misleading prior to or shortly after their issuance and had the ability and opportunity to prevent their issuance or to cause them to be corrected. Because of their positions with the Company, and their access to material information available to them but not to the public, the Individual Defendants knew that the adverse facts specified herein had not been disclosed to and were being concealed from the public, and that the positive representations being made were then materially false and misleading. The Individual Defendants are liable for the false statements and omissions pleaded herein.

48. The Defendants referenced above in ¶¶38-45 are sometimes referred to herein collectively as the "SCE Defendants."

49. Defendant SCE Trust VI is a statutory trust formed under the laws of the State of Delaware by SCE on June 12, 2017.

50. Defendant Connie J. Erickson ("Erickson") has served as Vice President and Controller of SCE since May 2014.

51. Defendant J.P. Morgan Securities LLC ("J.P. Morgan") was one of the primary underwriters of the Company's Offering and assisted in the preparation and dissemination of Edison's Offering Documents. Additionally, J.P. Morgan acted as a representative for all of the underwriters involved in the Offering. J.P. Morgan's main offices are located at 277 Park Avenue, New York, NY 10172.

52. Defendant Morgan Stanley & Co. LLC ("Morgan Stanley") was one of

the primary underwriters of the Company's Offering and assisted in the preparation and dissemination of Edison's Offering Documents. Additionally, Morgan Stanley acted as a representative for all of the underwriters involved in the Offering. Morgan Stanley's main offices are located at 1585 Broadway, New York, NY 10036.

53. Defendant RBC Capital Markets, LLC ("RBC") was one of the primary underwriters of the Company's Offering and assisted in the preparation and dissemination of Edison's Offering Documents. Additionally, RBC acted as a representative for all of the underwriters involved in the Offering. RBC's main offices are located at 200 Vesey Street, 9th Floor, New York, NY 10281.

54. Defendant Wells Fargo Securities, LLC ("Wells Fargo") was one of the primary underwriters of the Company's Offering and assisted in the preparation and dissemination of Edison's Offering Documents. Additionally, Wells Fargo acted as a representative for all of the underwriters involved in the Offering. Wells Fargo's main offices are located at 550 S. Tryon St., 6th Floor, D1086-060, Charlotte, NC 28202.

55. Defendant Citigroup Global Markets Inc. ("Citigroup") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. Citigroup's headquarters are located at 390-388 Greenwich St., New York, NY 10013.

56. Defendant Mizuho Securities USA LLC ("Mizuho") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. Mizuho's headquarters are located at 320 Park Avenue, 12th Floor, New York, NY 10022.

57. Defendant MUFG Securities Americas Inc. ("MUFG") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. MUFG's headquarters are located at 1633 Broadway, 29th Floor, New York, NY 10019.

58. Defendant PNC Capital Markets LLC ("PNC") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. PNC's headquarters are located at 225 Fifth Ave., 3 PNC Plaza, 26th Floor, Pittsburgh, PA 15222.

59. Defendant TD Securities (USA) LLC ("TD") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. TD's headquarters are located at 31 West 52nd Street, New York, NY 10019.

60. Defendant U.S. Bancorp Investments, Inc. ("U.S. Bancorp") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. U.S. Bancorp's headquarters are located at 800 Nicollet Mall, Minneapolis, MN 55402.

61. Defendant Academy Securities, Inc. ("Academy") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. Academy's headquarters are located at 277 Park Ave., 35th Floor, New York, NY 10172.

62. Defendant C.L. King & Associates, Inc. ("C.L. King") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. C.L. King's headquarters are located at 9 Elk Street, Albany, NY 12207.

63. Defendant Drexel Hamilton, LLC ("Drexel Hamilton") was an underwriter of the Company's Offering and assisted in the preparation and dissemination of the Offering Documents. Drexel Hamilton's headquarters are located at 77 Water Street, Suite 201, New York, NY 10005.

64. Defendant Samuel A. Ramirez & Company, Inc. ("Ramirez & Co.") was an underwriter of the Company's Offering and assisted in the preparation and

dissemination of the Offering Documents. Ramirez & Co.'s headquarters are located at 61 Broadway, Suite 2924, New York, NY 10006.

65. The Defendants referenced above in ¶¶51-64 are sometimes referred to herein collectively as the "Underwriter Defendants."

66. Pursuant to the Securities Act, the Underwriter Defendants are liable for the false and misleading statements in the Offering Documents.

67. Representatives of the Underwriter Defendants were required to conduct an adequate and reasonable investigation into the business and operations of Edison, an undertaking known as a "due diligence" investigation, yet failed to do so.

68. All of the defendants referenced above are referred to collectively herein as "Defendants."

SUBSTANTIVE ALLEGATIONS

Background

Edison and SCE

69. Edison, which was founded in 1886 and is based in Rosemead, California, is the parent holding company of SCE. Edison is a publicly traded company that owns and/or manages an "Electric Plant" as defined in Section 217 of the California Public Utilities Code ("Utilities Code"), and, like its subsidiary SCE, is both an "Electric Corporation" and a "Public Utility" pursuant to, respectively, Sections 218(a) and 216(a) of the Utilities Code. It develops and operates energy infrastructure assets related to the production and distribution of energy such as power plants, electric lines, natural gas pipelines, and liquefied naturel gas receipt terminals.

70. Edison supplies electricity primarily to residential, commercial, industrial, agricultural, and other customers, as well as public authorities through transmission and distribution networks. Edison subsidiaries provide customers with public utility services, and services related to the generation of energy, generation of

electricity, transmission of electricity and natural gas, and the distribution of energy. Its transmission facilities consist of lines ranging from 33 kV to 500 kV and substations. Its distribution system comprises approximately 53,000 line miles of overhead lines, 38,000 line miles of underground lines, and 800 substations located in California. Edison serves approximately five (5) million customers.

71. SCE, based in Los Angeles County, is an investor-owned public utility and one of the nation's largest electric utilities, serving a 50,000 square-mile area within Central, Coastal, and Southern California. SCE is in the business of providing electricity to the residents and businesses of Central, Coastal, and Southern California through a network of electrical transmission and distribution lines. SCE is both an "Electrical Corporation" and a "Public Utility" pursuant to, respectively, Sections 218(a) and 216(a) of the Utilities Code.

<u>California's "New Wildfire Reality</u>"

72. The frequency of western U.S. wildfires has increased by 400% since 1970, with California among the states that have experienced the worst damage.

73. According to a recent report by Governor Newsom's wildfire "Strike Force": "The state's fire season is now almost year round …. Wildfires are not only more frequent but far more devastating. Fifteen of the 20 most destructive wildfires in the state's history have occurred since 2000; ten of the most destructive fires have occurred since 2015."[4]

74. The recent Strike Force report cites a variety of causes for the increase in number and severity of California wildfires, including "climate change, development

[4] *Wildfires and Climate Change: California's Energy Future*, A Report from Governor Newsom's Strike Force, Exec. Summary at 1 (Apr. 12, 2019), publicly-available at: https://www.gov.ca.gov/wp-content/uploads/2019/04/Wildfires-and-Climate-Change-California%E2%80%99s-Energy-Future.pdf

patterns, [and] deferred utility equipment maintenance."[5]

75. However, as one wildfire prevention activist noted in the midst of the Woolsey Fire catastrophe, "[u]tility-caused wildfires are not 'natural' disasters, even if climate change contributes to their severity …. Such fires do not start without a source, and if utility equipment is old, poorly inspected or poorly maintained it is more likely to be a source of ignition."[6]

76. The recent Strike Force report broadly concurs with this view in explaining that "California's electric utilities must be part of the solution to this problem. In the past four years, equipment owned by California's three largest investor-owned utilities sparked more than 2,000 fires. Utility-caused fires tend to spread quickly and be among the most destructive." (Citation omitted).[7] The report goes on to insist that "[o]ur utilities—public and private—must make needed investments to reduce the risk of utility-ignited fires and, with the new reality of climate change, must do so now."[8]

77. Due to inverse condemnation, which holds a utility strictly liable for wildfire damages if the utility's equipment ignites a wildfire, California's investor-owned utilities stand to incur massive losses stemming from what the Strike Force report calls "a new wildfire reality" and the resultant increase in fire damages:

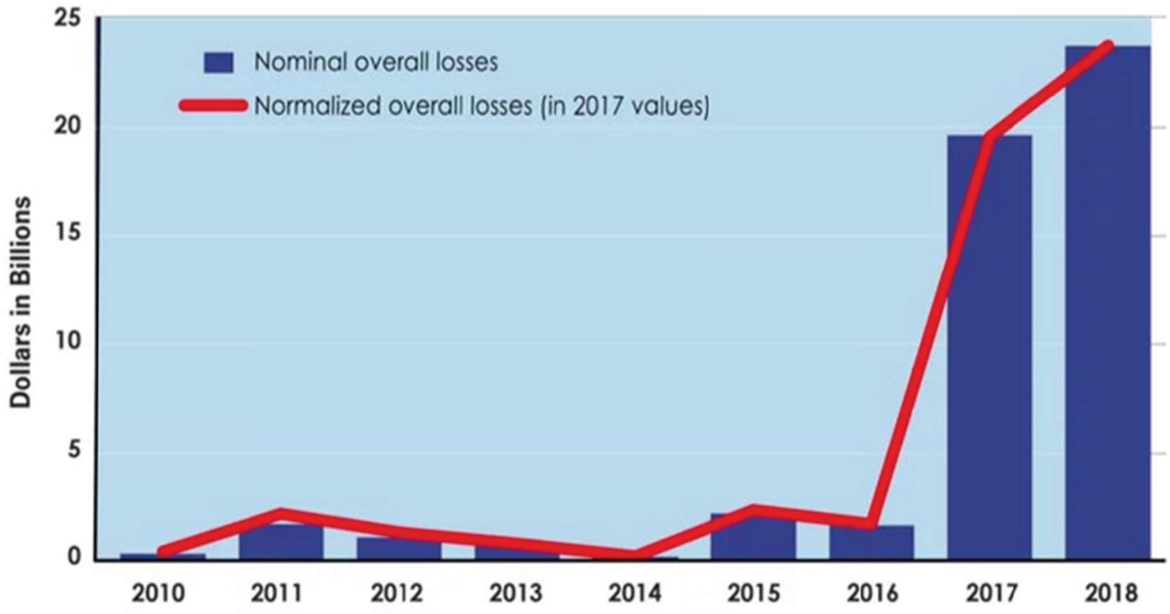
[5] *Id* at. 26.

[6] Jeff McDonald, "A 2016 California Law Meant to Prevent Wildfires. Utility Regulators Delayed Enforcing It." *Tribune News Service* (Dec. 11, 2018), publicly-available at: https://www.governing.com/topics/transportation-infrastructure/tns-california-wildfire-power-2016-prevention-camp-fire-paradise.html

[7] *Id.* at 4.

[8] *Id.*

Figure-09
Wildfire Damages[35]



[*Source*: Strike Force report at 26.]

78. As the Strike Force report puts it, "[f]inancial experts have opined that these utilities are likely one major fire away from bankruptcy."[9]

79. In a February 2019 interview, Defendant Pizarro stated that "This is a really serious issue that could absolutely impair the health of utilities in this state …. I don't want to speculate about bankruptcy, but this is serious. And the current approach is just not sustainable."

80. Edison, however, has long been aware of its obligation to minimize wildfire risk. In January 2014, then-Governor Jerry Brown declared a state of emergency due to California's continued drought conditions. In June 2014, pursuant to Resolution ESRB-4, CPUC directed SCE and all investor-owned utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility

[9] *Id.*, Exec. Summary at 1.

facilities.

81. No later than November 2015, prior to the start of the Class Period, SCE had identified and was aware that its electrical facilities were located in areas where, due to environmental and/or weather conditions, they posed an increased risk of wildfires, including that approximately 75% of SCE's territory was in a designated "High Fire" area; 640,000 trees within SCE's territory were located in "High Fire" areas; and 993 SCE circuits were in "High Fire" areas.[10]

82. In June 2017, prior to the Thomas Fire, SCE advised CPUC that "the insurance market has reacted more severely to the California wildfire risk, and this has significantly increased SCE's premiums."[11]

Relevant Statutory and Regulatory Provisions

83. At all times during the Class Period, Edison was obligated to properly construct, inspect, repair, maintain, manage, and/or operate its power lines and/or other electrical equipment and to keep vegetation properly trimmed at a safe distance so as to prevent foreseeable contact with such electrical equipment.

84. Edison was required to comply with a number of statutes, regulations, and standards in the construction, inspection, repair, maintenance, management, ownership, and/or operation of its power lines and other electrical equipment, as discussed below.

85. Pursuant to Section 451 of the Utilities Code, "[e]very public utility shall

[10] SCE, Senate Informational Hearing: Wildfire Safety at 2 (Nov. 18, 2015), publicly-available at: http://seuc.senate.ca.gov/sites/seuc.senate.ca.gov/files/11-18-15_edison_testimony.pdf

[11] SCE, General Rate Case 2018, Rebuttal Testimony, Administrative & General (A&G) Volume 4 - Property & Liability Insurance at 9 (June 16, 2017), publicly-available at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/DCE44214E863CE3F882581410082EBDD/$FILE/SCE24V04.pdf

furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities ... as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

86. More recently, California Senate Bill (SB) 901 (passed and signed into law in 2018) provides that electric utilities must "construct, maintain, and operate [their] electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment."

87. To meet this safety mandate, Edison is required to comply with a number of design standards for its electrical equipment, as stated in CPUC General Order 95. For example, in extreme fire areas, Edison also must ensure that its power lines can withstand winds of up to ninety-two (92) miles per hour.

88. Edison must also follow several standards to protect the public from the consequences of vegetation and/or trees coming into contact with its power lines and other electrical equipment. Pursuant to Public Resources Code § 4292, Edison is required to "maintain around and adjacent to any pole or tower which supports a switch, fuse, transformer, lightning arrester, line junction, or dead end or comer pole, a firebreak which consists of a clearing of not less than 10 feet in each direction from the outer circumference of such pole or tower."

89. Relatedly, Public Resources Code § 4293 mandates Edison maintain clearances of four to ten feet for all of its power lines, depending of their voltage. In addition, "[d]ead trees, old decadent or rotten trees, trees weakened by decay or disease and trees or portions thereof that are leaning toward the line which may contact the line from the side or may fall on the line shall be felled, cut, or trimmed so as to remove such hazard."

90. CPUC General Order ("GO") 165 requires Edison to inspect its distribution facilities to maintain a safe and reliable electric system. In particular,

Edison must conduct "detailed" inspections of all of its overhead transformers in urban areas at least every five years. In addition, every ten years, Edison is required to conduct "intrusive" inspections of its wooden poles that have not already been inspected and are over fifteen years old.

91. Edison publicly acknowledged these duties in November 2015, when SCE falsely represented to the California State Senate Subcommittee on Gas, Electric, and Transportation Safety (as well as the general public, including investors) that "[a] number of" its "existing practices" had been "enhanced and new activities adopted since 2007 to further improve SCE's ability to manage wildfire risk."[12]

92. Sections 451 and 399.2(a) of the Utilities Code give electric utilities authority to shut off electric power in order to protect public safety. This authority includes shutting off power for the prevention of fires caused by strong winds.

Edison's Prior Fires and Outages

93. Edison was aware of the significant risks created by its ineffective vegetation management programs, unsafe equipment, poor risk assessment, and/or aging infrastructure for decades before the Thomas and Woolsey Fires began, and Edison has been repeatedly fined and/or cited for causing massively disruptive fires and power outages.[13]

94. Since 2007, CPUC has levied over $78 million in fines against Edison for electric and fire-related incidents.[14]

95. The 1993 San Bernardino Mill Creek fire was caused by a failure of

[12] SCE, Senate Informational Hearing: Wildfire Safety at 10.

[13] "Pole loading" is the calculation of whether a pole meets certain design safety factors based on wind in its location and the facilities attached to the pole.

[14] http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Electric_and_Fire_Related_Fines.pdf

Edison's overhead power line equipment. High winds caused a power line to break, spark a fire, and damage a nearby home.

96. In 1997, Edison's failure to trim trees near and around its power lines near its distribution lines caused a 25,100 acre fire in Riverside County.

97. In 1998, Edison signed an undisclosed settlement in relation to a fire in which most of Stearns Wharf in Santa Barbara was burned. In that instance, an investigation concluded that Edison was responsible.

98. In 2006, Edison agreed to pay $14 million to settle a federal suit stemming from the 1994 Big Creek Forest Fire. The suit alleged that Edison did not comply with vegetation clearance requirements around a high-voltage transformer that exploded and ignited nearby dry grass. The Government also alleged that Edison didn't install appropriate animal guards at the location, and that Edison employees also lacked the equipment to stop the fire before it went into the forest.

99. Edison was also held responsible for its role in the 2007 Malibu Canyon Fire. The fire began when three wooden utility poles snapped during high Santa Ana winds and ignited nearby brush. That fire burned 3,836 acres and destroyed or damaged over thirty (30) structures. CPUC alleged that at least one of the poles that fell was overloaded with telecommunication equipment in violation of the applicable standards.

100. CPUC also alleged that Edison misled investigators about the circumstances of the fire. Specifically, "SCE admit[ted] that it violated Rule 1.133 in its communications with the Commission by: 1) not identifying pole overloading and termite damage as possible factors in the pole failures; 2) not providing SED with an accurate copy of an SCE employee's field notes; and 3) not admitting that not all

relevant evidence had been preserved."[15]

101. In response to its responsibility for the Malibu Canyon Fire, Edison agreed to conduct a safety audit and remediation of its utility poles in the Malibu area. In 2013, CPUC fined Edison $37 million for its role in the fire, with $17 million of the settlement to be spent on pole loading assessments and resulting remediation work in Malibu Canyon and surrounding areas.

102. Under the settlement agreement with CPUC, Edison admitted it violated the law by not taking prompt action to prevent its poles in Malibu Canyon from becoming overloaded. Further, Edison admitted that a replacement pole did not comply with CPUC's safety regulations for new construction, which should have caused Edison to take steps to remedy the situation.

103. Edison was also found liable for the 2007 Nightsky fire in Ventura County. The fire burned fifty-three (53) acres and started when sagging, overloaded power lines arced and sparked. The jury determined that Edison had not properly maintained its lines, that there were problems with insulators or conductors on Edison's poles, and that phase to ground faults, relay-tripping, and phase-to-phase imbalances indicated the existence of a chronic, unfixed hazard.

104. In November and December of 2011, Santa Ana winds swept through Edison's territory, knocking down utility facilities, uprooting trees, and causing

---

[15] Rule 1.1 of the Commission's Rules of Practice and Procedure states that:

> Any person who signs a pleading or brief, enters an appearance, offers testimony at a hearing, or transacts business with the Commission, by such act represents that he or she is authorized to do so and agrees to comply with the laws of this State; to maintain the respect due to the Commission, members of the Commission and its Administrative Law Judges; ***and never to mislead the Commission or its staff by an artifice or false statement of fact or law*** (emphasis added).

prolonged power outages (the "San Gabriel Valley windstorms"). Over two-hundred (200) wood utility poles and 1000 overhead electrical lines were affected. CPUC's Safety & Enforcement Division ("SED") performed an investigation and concluded that Edison and communication providers who jointly owned utility poles violated CPUC standards because at least twenty-one (21) poles and seventeen (17) wires were overloaded in violation of safety factor requirements. As a result, CPUC fined Edison $16.5 million.

105. In 2015, multiple power outages on Edison's secondary network system, the electric distribution system that serves downtown Long Beach, occurred, including a five-day outage from July 15 to July 20, 2015, and a four-day outage from July 30, 2015 to August 3, 2015. The Long Beach outages primarily affected 3,825 customers served by Edison's Long Beach secondary network, but at times extended to 30,000 customers, including customers who receive their power from radial circuits that also feed the secondary network. Along with these outages, the failure of electric facilities caused fires in several underground structures, resulting in explosions that blew manhole covers into the air.

106. An investigation into the Long Beach outages revealed leaking, hot, deteriorated, and otherwise damaged cables, none of which were identified by SCE in previous inspections.

107. In connection with the Long Beach outages, SCE admitted that it had violated CPUC regulations by, *inter alia*: (i) failing to operate, monitor, and maintain its secondary network; (ii) failing to properly install or support cables where the fire had begun; (iii) failing to conduct required inspections. SCE further admitted that it violated the Utilities Code's mandate that utilities "promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

108. On November 7, 2015, a wildland fire known as the "Potrero Fire" ignited

in Thousand Oaks, California. The responding Ventura County Fire Protection District investigator noted in his report that he saw "multiple broken ceramic components of power line electrical equipment in the area" that "appeared to have been there prior to the fire." SCE was ultimately held to be in violation of GO 95, Rule 44.3 for failing to replace or reinforce an unsafe utility pole.

109. During the same period in 2017, the Liberty Fire burned three-hundred (300) acres and destroyed one structure and one outbuilding. SCE issued a press release acknowledging its equipment was associated with the fire's ignition. Cal Fire has confirmed SCE equipment was the cause of the Liberty Fire.

Edison's Safety Violations During the Class Period

110. Edison was aware of the significant risks created by its ineffective vegetation management programs, unsafe equipment, and/or aging infrastructure both before and during the Class Period, when Edison was repeatedly cited and/or fined for safety-related violations, including one involving a fatality. Nevertheless, Edison touted its safety practices to investors during the Class Period.

111. On May 15, 2014, an Edison overhead conductor separated and fell to the ground at the Company's Whittier facility. A person came into contact with the downed, yet still-energized, conductor and was fatally electrocuted. SED's investigators found that the overhead conductor separated at an overhead connector, and that Edison did not maintain the connector for its intended use. Consequently, Edison received a $50,000 citation.

112. In October 2018, CPUC fined SCE $8 million for failing to maintain electrical equipment that injured three U.S. Marines in Twentynine Palms in 2015. In that incident, three active-duty Marines were riding all-terrain vehicles in the desert when one ran into a fallen copper power line that was hanging less than eight feet off the ground and suffered a laceration to his neck. A comrade who rushed to his aid

sustained third-degree burns to his left hand, left bicep and abdomen. A third Marine was also badly shocked by the line.

113. CPUC initially fined SCE $300,000 in connection with the Twentynine Palms incident. SCE appealed that fine, and CPUC reopened its investigation. During the second probe, CPUC discovered that workers had failed for years to replace a nut that helped secure the overhead conductor, prompting CPUC to increase its fine against SCE. CPUC explained that SCE "failed to recognize the severity and hazard of this violation … Consequently, [the utility] labeled this hazardous and dangerous condition as priority level 3 and allowed the unsafe condition to remain uncorrected for several years."

114. CPUC's Electric Safety and Reliability Branch conducts regular "electric audits" of SCE districts during which commission employees review SCE records and field inspections of SCE facilities.

115. Almost all of CPUC's SCE-related audits conducted from 2015 to 2018 cite violations of GO 95for failure to complete work orders by their scheduled due date of corrective action. The audits flag safety violations, most of which related to pole safety, and some of which presented clear fire hazards.

116. An April 4, 2016 to July 15, 2016 audit of SCE's Tehachapi District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where, from 2013 to 2016, three work orders were completed past their scheduled date of corrective action;
- GO 95 where ground moulding was loose or missing;
- GO 95 where SCE failed to notify other companies of (a) low communications cable clearance; and (b) a CIP trunk line touching the ground; and
- GO 95 where high voltage signs on poles was either damaged or missing.

117. A July 11, 2016 to July 15, 2016 audit of SCE's Huntington Beach

District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where, from 2013 to 2016, seven work orders were completed past their scheduled date of corrective action;
- GO 95 where the above ground clearance of communication service drops on poles was six feet and SCE failed to notify the other companies of this safety hazard when it last inspected the poles;[16]
- GO 95 where a communication service drop was wrapped around the base of the pole, and SCE did not notify the other company of this safety hazard when it last inspected the pole;
- GO 95 where climbing space on a pole was obstructed by a communication cable that was wrapped around the base of the pole;
- GO 95 where ground moulding on poles was warped, bowing out, or missing altogether;
- GO 95 where a service drop was touching the roof of a building;
- GO 95 where a down guy wire on a pole was not taut; and
- GO 95 where pole steps were bent, damaged, or missing.

118. An October 10, 2016 to October 14, 2016 audit of SCE's Arrowhead District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where, from 2013 to 2016, an SCE work order was completed past its scheduled date of corrective action;
- GO 95 where down guy wires were not taut or, lacked the appropriate clearance, or touched a pole crossarm;

---

[16] A "drop" is the portion of a device directly connected to the internal station facilities, such as toward a telephone switchboard, toward a switching center, or toward a telephone exchange.

- GO 95 where high voltage signs on poles was either damaged or missing;
- GO 95 where ground moulding on poles was damaged; and
- GO 95 where conductors supported by poles showed abrasion from vegetation contact.

119. An October 10, 2016 to October 14, 2016 audit of SCE's substation audit of SCE's Orange County and Lighthipe Switching Centers found SCE in violation of, *inter alia*:

- GO 174 where the barbed wire along the southwestern perimeter fence of the Lucas Substation was broken;[17]
- GO 174 where the cable trench covers located northeast of the North Bus A Section 66 kV disconnect of the Hinson Substation were damaged;
- GO 174 where the Peanut 12 kV Circuit Breaker of the Chestnut Substation had a leak on the bottom of tank;
- GO 174 where the No. 2 Bank (12 kV Circuit Breaker) of the Lampson Substation was missing an animal guard;
- GO 174 where the 66 kV No. 2 Bank (south unit) of the Cabrillo Substation was leaking oil; and
- GO 174 where the The Perch 12 kV Circuit Breaker of the Bayside Substation was leaking oil.

120. A February 6, 2017 to February 10, 2017 audit of SCE's Blythe District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where, from 2014 to 2017, four work orders were completed

[17] CPUC GO 174, Rule 12, General, states in part: Substations shall be designed, constructed and maintained for their intended use, regard being given to the conditions under which they are to be operated, to promote the safety of workers and the public and enable adequacy of service.

past their scheduled date of corrective action;

- GO 95 where multiple poles were damaged, in one case just two feet above the ground-line of the pole.

121. An April 17, 2017 to April 21, 2017 audit of SCE's Kernville District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where three work orders were past their scheduled date of corrective action;
- GO 95 where ground moulding on poles was damaged or missing; and
- GO 95 where guy wires were (a) not taut and/or (b) hanging between vegetation.

122. An October 16, 2017 to October 20, 2017 audit of SCE's Monrovia District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where three work orders were completed past their scheduled date of corrective action;
- GO 95 where one or more insulators on a pole were "sunken";
- GO 95 where ground moulding was damaged on three poles, exposing ground wire in two instances;
- GO 95 where climbing spaces on five poles were obstructed by communications cables, vegetation, tree branches, and/or a "buddy pole";[18]
- GO 95 where a service conductor supported on a pole was contacting a bare secondary cable on the same circuit; and
- GO 95 where down guy wires on two poles were contacting communications cables at mid-span.

123. An October 30, 2017 to November 3, 2017 audit of SCE's Long Beach

[18] According to CPUC, a "buddy pole" is an old pole that should be removed, but is instead left in the field.

District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where, from 2014 to 2017, SCE completed ***fifty-four (54)*** work orders past their scheduled date of corrective action;
- GO 95 where nine high voltage signs were damaged; and
- GO 95 where ground moulding on four poles was damaged, including two instances of exposed ground wires.

124. A February 5, 2018, to February 9, 2018 audit of SCE's Antelope Valley District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where, from 2014 to 2017, SCE completed ***forty-six (46)*** work orders past their scheduled date of corrective action; additionally, as of the audit date, SCE records indicated that it had ***nineteen (19)*** work orders open that were past their scheduled due date of corrective action; and
- GO 95 where ground moulding was damaged on six poles, exposing ground wire in each instance.

125. A March 5, 2018, to March 9, 2018 audit of SCE's San Joaquin Valley District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where, from 2014 to 2017, SCE completed twenty-two (22) work orders past their scheduled date of corrective action.

126. An April 16, 2018, to April 20, 2018 audit of SCE's Catalina Island District found SCE in violation of, *inter alia*:

- GOs 95 and 165 where three work orders were completed past their scheduled date of corrective action;
- GO 95 where service drops and communications cables came into contact in two instances;
- GO 95 where conductors were touching; and
- GO 95 where there were several discrepancies with the pole loading calculation

given that: (1) SCE's calculation with respect to wind load underestimated the pole's lateral deflection and the amount of bending moment caused by the vertical loads; (2) SED Staff found that the three communications span cables had higher attachment height on the subject pole than on the two adjacent poles; (3) SCE's calculation did not appear to take into account the increase in vertical loading on the subject pole that is caused by uneven attachment height; and (4) SCE's pole loading calculation did not appear to include the additional wind loading on the splice boxes, amplifiers, filters, and other incidental wiring and equipment on the communications span cables that are attached to the pole.

127. A May 21, 2018 to May 25, 2018 audit of SCE's Whittier District found SCE in violation of, *inter alia*:

- GO 95 where a service drop supported on a pole and serving a home was touching the roof of the aforementioned home;
- GO 95 where the insulator bracket supporting the service drop to the aforementioned home was detached and hanging below the eave of the home;
- GO 95 where, in three instances, pole crossarms supporting conductors were deteriorated and/or broken;
- GO 95 where a primary conductor on a pole exhibited "birdcaging" near a splice;[19]
- GO 95 where ground moulding was broken at multiple locations and peeling away from the pole, exposing the ground wire; and
- GO 95 where a palm tree growing parallel to the pole had palm fronds obstructing the designated climbing space.

[19] "Birdcaging" or "bird-caging" refers to a situation in which a wire in an impacted strand, *i.e.*, forced into compression, will separate from the core wire.

Edison's Aging Electrical Infrastructure

128. For years prior to the outbreak of the Thomas and Woolsey Fires, the SCE Defendants knew that their miles of aging power lines and utility poles posed a serious safety risk of triggering wildfires.

129. On September 1, 2016, in connection with its 2018 General Rate Case ("GRC"),[20] SCE acknowledged that "[p]oles in high-fire areas are [ ] more likely to lead to wildfires."[21]

130. According to a Fact Sheet disseminated by SCE, "[m]ost of SCE's poles were installed just after World War II and the methods we currently use to measure safety have changed."[22]

131. In its 2015 GRC, SCE further qualified that "[t]he average service life of these poles is 45 years."[23] More ominously, SCE's analysis of historical data found that

---

[20] GRCs are proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. *See* http://www.cpuc.ca.gov/General.aspx?id=10431. GRCs are categorized according to "test year," or the actual historical period of time for which financial and operating data will be required. Therefore, the actual GRC proceedings themselves will typically predate the test year, *e.g.*, proceedings for SCE's 2018 GRC primarily date from 2015-2017.

[21] SCE, 2018 General Rate Case, Transmission & Distribution (T&D) Volume 1 – Operational Overview and Risk-Informed Decision-Making at 36 (Sept. 1, 2016), publicly-available at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/B6856C8981232F75882580210065C0AF/$FILE/SCE02V01.pdf

[22] https://www.sce.com/sites/default/files/inline-files/PoleLoadingProgramFactSheet.pdf

[23] SCE, 2015 General Rate Case, Transmission and Distribution (T&D) Volume 1 - T & D Policy at 6 (Nov. 2013), publicly-available at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/B394F106B39238E888257C210080EE7A/$FILE/SCE-03%20Vol.%2001.pdf

found that poles over 70 years old have an ***80% chance of failure***.[24]

132. Also in its 2015 GRC, SCE identified pole failure as its second-highest risk – out of ten top risks – relating to safety to safety and reliability.[25]

133. Edison's service territory includes 1.4 million utility poles, and 63.3 percent of Edison's electric transmission and distribution system is comprised of overhead lines.

134. In a 2015 report to CPUC addressing the risk factors in its electrical system, Edison noted that "[w]ood poles are more susceptible to decay, woodpecker damage, or failure during a fire compared to concrete or steel poles." Furthermore, poles located in high-wind areas such as in Southern California are "exposed to higher stresses …. [i]f a pole fails and starts a wildfire, the fire is more likely to spread in a high-wind area" and "[i]f a pole fails in service, wildfires are more likely to start in high-fire regions …."[26]

135. In January 2017, SED observed that SCE's pole-loading study sample submitted in connection with its 2018 GRC:

> …. did not utilize a statistically random selection of poles across its service territory. Also, when SCE conducted analysis to compare its previous methodology with a revised sampling methodology, it used completely different sampling poles, not the same cohort as in its original analysis. SED concludes that there is no way to do an "apples-to-apples" comparison

---

[24] CPUC/SED, Staff Report, Southern California Edison Company, General Rate Case, 2015-2017, Application 13-11-003 at 13(Aug. 15, 2014).

[25] *Id.* at 13.

[26] Safety Model Assessment Before the Pub. Utils. Comm'n of the State of Cal. (May 2015), publicly-available at : http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/4841D9996 A06A2B288257E38007AA374/$FILE/A.15-05-XXX%20SMAP%20-%20SCE 01%20SMAP% 20Testimony_M.%20Marelli_S.%20Menon_N.%20Woodward.pdf

> between the previous pole loading assessment methodology and the new revised methodology.[27]

136. In 2017, well before the occurrence of the Liberty and Thomas Fires, CPUC ordered that the creation of a shared utility pole database be investigated for the express purpose of addressing the problems with Edison's infrastructure that caused the 2007 Malibu Canyon Fire and electrical problems in the 2011 San Gabriel Valley windstorms, where weak and faulty power poles maintained by Edison left thousands of people without power for days:

> Poorly maintained poles and attachments have caused substantial property damage and repeated loss of life in this State. Unauthorized pole attachments are particularly problematic. A pole overloaded with unauthorized equipment collapsed during windy conditions and started the Malibu Canyon Fire of 2007, destroying and damaging luxury homes and burning over 4500 acres. Windstorms in 2011 knocked down a large number of poles in Southern California, many of which were later found to be weakened by termites, dry rot, and fungal decay.[28]

137. In the June 29, 2017 CPUC press release for its order regarding the creation of a pole database, CPUC President Michael Picker explained that "[p]lain old wooden poles, along with their cousins, the underground conduits, are work horses, carrying most of our power and telecommunications. They sometimes get crowded and fail, causing outages and fires because of all the equipment crammed onto them."

138. President Picker further stated that, "[n]ot knowing where all the poles are

---

[27] SED, Risk and Safety Aspects of Southern California Edison's 2018-2020 General Rate Case Application 16-09-001 (Jan. 19, 2017), publicly-available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Risk_Assessment/SCE%202018%20GRC%20Report%20Final%20with%20Appendix%20A.pdf

[28] CPUC Order Instituting Investigation into the Creation of a Shared Database or Statewide Census of Utility Poles and Conduit (July 10, 2017), publicly-available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M191/K656/191656519.PDF

and who owns them, how loaded they are, how safe they are, and whether they can handle any additional infrastructure, is problematic to both the utilities and to the CPUC. Creating a database of utility poles could help owners track attachments on their poles and manage necessary maintenance and rearrangements, and can help the CPUC in our oversight role."[29]

139. In response to the proposed shared database and a related Administrative Law Judge (ALJ) request for comments regarding same, SCE submitted comments to CPUC on February 8, 2018.[30] In its comments, SCE argued that (1) the requested feedback on database specifics was "premature" and (2) many of the ALJ's proposed database variables were "problematic" or "not feasible" given the incomplete state of SCE's own internal databases.[31] The rulemaking process with respect to the proposed pole database remains ongoing and incomplete.

140. Less than two months before the Woolsey Fire, SCE, in prepared testimony before CPUC, stated that "the two greatest ignition drivers are 'contact from object' followed by 'equipment/facility failure.' These historical statistics are consistent with the suspected ignition source data for California's investor-owned

---

[29] CPUC Press Release, "CPUC to Examine Utility Pole Safety and Competition; Considers Creation of Pole Database" (July 29, 2017), publicly-available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M191/K560/191560905.PDF

[30] *See generally* Southern California Edison Company's (U 338-E) Comments on Assigned Commissioner and Assigned Administrative Law Judge's Ruling Requesting Comment on Creation of Shared, Statewide Database of Utility Pole and Conduit Information (Feb. 8, 2018), publicly-available at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/A69CD4FD0681664D8825822F00005290/$FILE/I1706027%20et%20al-SCE%20Comments%20on%20Ruling%20re%20Creation%20of%20Shared%20Database.pdf

[31] *See id.* at 2-3.

electric public utilities by the CPUC's Safety and Enforcement Division."[32]

Edison Failed to Maintain its Electrical Infrastructure

141. In addition to having no reasonably functional method to track the condition of its infrastructure of its pole stock, Edison failed to timely and properly maintain, inspect, and/or monitor its electrical infrastructure, despite knowing that its failure to do so could trigger highly-destructive fires, as had already happened repeatedly.

Pole Inspection Issues

142. While SCE has admitted that it has the ability to "underground" sections of power lines – and thereby do away with poles altogether – as well as otherwise "fire-harden" its distribution system, it has not proposed doing so on a system-wide basis.[33] Instead, those solutions would apply only to "sections of lines" depending on cost-benefit considerations.[34]

143. In its 2015 GRC, SCE revealed that while it "should be replacing over 31,000 poles every year", it was, in fact, "replac[ing] approximately 14,000-18,000 poles each year" and "that approximately half of these poles replacements [we]re based on GO 165-driven pole inspections" rather than any technologically-current tracking system. Shockingly, SCE admitted that during the previous five years, it had replaced just <u>8,000 poles per year</u> (on average). SCE's own submission concluded that "***[t]his is***

---

[32] *See* SCE, Prepared Testimony in Support of Southern California Edison Company's Application for Approval of Its Grid Safety and Resiliency Program – Annotated at 33 (Sept. 10, 2018), publicly-available at: https://www.tellusventure.com/downloads/cpuc/poles/sce_testimony_grid_safety_10sep2018.pdf

[33] SCE, 2015 GRC, T&D Vol. 1 at 29.

[34] *Id.*

simply not enough." (Emphasis added).[35]

144. Former Employee ("FE") 1, who worked as a Planner in SCE's Deteriorated Pole Replacement Program ("DPRP") – which was initiated in 2013 – from January 2014 to March 2018, said the DPRP involved replacing an enormous number of deteriorated poles: in 2014, SCE issued about 40,000 work orders for pole replacements. In 2015, it was about 45,000.

145. The figures provided by FE1 stand in marked contrast to SCE's own reporting: in 2016, SCE told CPUC that it had replaced just over 23,000 poles in connection with the DPRP, or slightly more than half of its issued work orders.[36]

146. FE2 was a contractor for SCE between July 2017 and October 2018. Prior to that, FE2 was SCE's South Bay District Manager between June 2014 and January 2016. South Bay is one of the largest and most populous districts in SCE's territory.

147. As District Manager, FE2 learned that the following SCE territories regularly did not hit targets for annual pole replacements: Metro East, North Coast, Santa Barbara and Ventura. Later, the Thomas Fire burned in Santa Barbara and Ventura Counties, while the Woolsey fire likewise affected Ventura County.

148. FE2 confirmed that the progress of each district's pole replacement work was part of the reports and briefing regularly given to Greg Ferree ("Ferree"), Vice-President of Distribution in SCE's Transmission & Distribution division. FE2 personally participated in meetings to provide that information to Ferree until FE2's

---

[35] SCE, 2015 GRC, T&D Vol. 1 at 6.

[36] SCE, General Rate Case 2018, Transmission & Distribution Volume 9, Poles at 5 (Sept. 1, 2016), publicly-available at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/2AC8389C4B47F640882580210066E4E5/$FILE/SCE02V09.pdf

departure in January 2016.

149. FE3 was a Biologist - Technical Specialist for SCE from April 2016 to March 2017, based in Rosemead, California. FE3 also worked for an environmental firm contracted with SCE to conduct biological surveys from 2013 to March 2016.

150. FE3 reported that under SCE's DPRP, a team of pole inspectors would conduct rotating rounds of surveys and tests on SCE's pole stock. Deteriorated poles were to be scheduled for replacement, but only after biologists, such as FE3, conduct a survey of the environmental impact of the replacement work, including impacts to bird nesting activity in, or, or near the pole.

151. The territory in which FE3 conducted surveys for SCE included the area where the Thomas Fire started.

152. FE3 said that upon any sign whatsoever that a bird was nesting on, in or near the pole, SCE would delay replacing the pole until the nest was no longer active.

153. FE3 stated that hundreds, if not a thousand or more, deteriorated poles were subsequently delayed for replacement due to SCE's approach to bird nesting. Specifically, FE3 estimated that approximately 20 to 30 percent of the deteriorated poles scheduled for replacement were delayed due to nesting birds in the years 2015 and 2016.

154. In regard to the Company's overly cautious approach to bird nesting, FE3 explained that Edison owned the right of way under the utility lines, so the Company had a right to replace poles with nests in them – just as a homeowner would have a right to cut down a tree in their yard with active nests in it.

155. FE3 further estimated that based on a cost of $23,400 per pole to replace transmission poles and $15,000 per-pole to replace distribution poles, delaying several hundred to a thousand poles per year could save Edison millions of dollars annually.

Pole-Loading Issues

156. Given Edison's longstanding problems with overloaded poles – as demonstrated by its role in causing the Malibu Canyon Fire – CPUC ordered SCE, as part of its 2012 GRC – to conduct a sample of SCE-owned and jointly-owned utility poles to determine whether pole loading complied with current legal standards. The resulting study, conducted by SCE, found that 22.3% of the more than 5,000 poles tested failed to meet current design standards.[37]

157. In the 2012 GRC, CPUC explicitly stressed the connection between SCE's pole remediation – or lack thereof – and fire risk:

> SCE did not establish its ability to undertake intrusive inspections of 130,000 wood poles per year during this rate cycle. However, we are concerned to the degree that some poles in SCE's service territory, particularly jointly-owned poles, may, unknown to SCE, be overloaded. ***Overloaded poles may break and thereby contribute to increased fire and other hazards***. (Emphasis added).[38]

158. In November 2013, SED sent a letter to CPUC discussing SCE's pole-loading study and recommending that: (1) SEC conduct wind analysis in its electrical equipment; (2) SCE should conduct a pole loading analysis of every pole carrying SCE facilities, employing a risk management approach, considering, at a minimum, fire risk, the presence of communications facilities and the number of overloaded poles in the area; and (3) SCE should commence pole mitigation measures as soon as possible,

---

[37] *See* CPUC, A Brief Introduction to Utility Poles (July 31, 2014) at 21, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPDUtilityPole.pdf

[38] *See* CPUC, Decision On Test Year 2012 General Rate Case For Southern California Edison Company (Dec. 10, 2012), publicly-available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M037/K668/37668274.pdf

and not wait for the pole loading analysis to be completed.[39]

159. In its 2015 GRC, SCE claimed to have designed a Pole Loading Program ("PLP") to "inspect and assess over 1.4 million poles over a seven-year period to identify and then remediate those poles that do not meet the current standards."[40]

160. From the outset, the PLP was a limited, piecemeal solution to the staggering risk posed by SCE's aging pole stock. First, SCE lacked sufficient data to coordinate the PLP with other maintenance efforts, including the DPRP.[41] Second, the PLP was designed to only "include poles that require repair or replacement solely because the pole fails a pole loading assessment."[42] That is, even where a pole had been identified as deficient based on an intrusive physical inspection, it would not be flagged for repair or replacement under the auspices of the PLP.

161. SCE claims that it started its PLP assessments in 2014, but will not complete pole remediation of overloaded poles until 2025.

162. As of January 2017, CPUC confirmed that SCE had no methodology in place to assess for varying levels of pole loading risks.[43]

163. In its 2015 GRC, SCE estimated that 22% of its utility poles were overloaded. ***An overview of SCE's pole-loading study from July 2013 revealed that***

---

[39] *Id.* at 22.

[40] SCE, 2015 General Rate Case Application (Nov. 2013), publicly-available at: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/D6B9C75A9D53E91288257C22007644A8/$FILE/APP%20SCE-10%20Vol.%2001%20Ch.%20IV.pdf

[41] SCE, 2015 GRC, T&D Vol. 1 at 29.

[42] *Id.* (Emphasis in original).

[43] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Risk_Assessment/SCE%202018%20GRC%20Report%20Final%20with%20Appendix%20A.pdf

overload was even higher in High Fire Threat Areas – at 23.7%.[44] Accordingly, SCE forecast it would perform an assessment of 205,754 poles in 2015.

164. However, in its 2018 GRC, SCE disclosed to CPUC that instead of assessing and remediating, it had simply modified its software used to calculate pole loading safety factors, thus reducing the percentage of poles requiring remediation to just 9%.[45]

165. FE1, who was a Planner in SCE's DPRP, stated that the modified software – called SPIDACalc – was less strict about which poles were likely to fail. Consequently, the number of work orders for pole replacements dropped to about 30,000 in 2016, the year before the Thomas Fire.

166. FE1 recalled that after the updated SPIDACalc software – which was deployed in the DPRP in addition to the PLP – began to lower the percentage of failing poles, SCE lowered its projected number for pole replacements each year, and replaced its construction contracts for a smaller scope of work.

167. In fact, SCE was unable to deploy the updated SPIDACalc until ***November 2015***, meaning that Edison had long since blown its assessment targets by the time it arrived at a technology-based rationale for its failure to assess SCE's overloaded pole stock.[46]

168. In early 2017, SED objected that "SPIDACalc software has not been independently verified and validated to test the results provided by the specific software version utilized for SCE's electrical distribution and transmission wood pole

---

[44] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Safety/Presentations_for_Commission_Meeting/SouthernCaliforniaEdisonPoleLoadingStudy(1).pdf

[45] SCE, General Rate Case 2018, T&D Vol. 9, Poles at 11.

[46] *Id.*

design … against G.O. 95 Overhead Line Construction safety requirements."[47]

169. In its 2018 GRC, SCE disclosed that it had failed to meet its 2015 projections to assess and repair overloaded poles. In contrast to its 2015 projections, SCE only actually performed PLP-related assessments of 142,382 poles in 2015, or 63,372 (30%) fewer than SCE claimed it would conduct, and as a result, SCE repaired 14,310 fewer overloaded poles than it forecast in 2015.

170. SCE further disclosed that out of the poles it assessed, it only performed repairs on 569 poles.

171. In its 2018 GRC, SCE claimed that it had considered changing the duration of its PLP from seven years to ten years – allowing for fewer pole assessments each year – and had adjusted its target assessment rate accordingly. However, SCE had never received official sign-off for the timeline change, and was ultimately required to proceed on a seven-year timeframe.

172. In prepared testimony dated September 10, 2018 – just before the Woolsey Fire – SCE informed CPUC that of the two primary categories of poles necessitating replacement under the PLP, one was "poles subject to particularly high winds []."[48] SCE further clarified that "[t]he specific poles that require replacement will disproportionately be those with higher wind loading conditions."[49]

<u>Vegetation Management Issues</u>

173. Edison also failed to manage fire-prone vegetation that threatened its electrical infrastructure (*see*, *e.g.*, ¶¶118, 121, 122 above).

---

[47] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Risk_Assessment/SCE%202018%20GRC%20Report%20Final%20with%20Appendix%20A.pdf

[48] Sept. 10, 2018 Prepared Testimony at 63.

[49] *Id.* at 63.

174. FE4 was employed as an Emergency Management Specialist at SCE from May 2014 to September 2015, and reported to Steven Oda, Business Resiliency senior manager.

175. FE4 explained that while the accepted role of emergency management involves the four aforementioned phases: mitigation, preparedness, response, and recovery, SCE lacked a focus on mitigation.

176. FE4 relayed that one of FE4's colleagues in Emergency Management at SCE, John Chappell ("Chappell"), had been working on and had proposed a fire mitigation program to SCE.

177. Chappell recommended the removal of large areas of dried vegetation around SCE electrical lines and/or equipment, which was creating an increased risk for wildfires.

178. It is FE4's understanding that no mitigation of the dried vegetation as proposed by Chappell was actually done by SCE.

Down Wires

179. FE5 was an Incident Investigation Manager at SCE from March 2010 to October 2014, and initially reported to Ed Antillon ("Antillon"), Director of Quality Assurance; followed by Greg Klugian ("Klugian"), who took over the job as Director after Antillon left SCE.

180. When FE5 left SCE toward the end of 2014, SCE did not have a program for regular inspections and upgrades of the conductor wires, fuses, or transformers that were all attached to the utility poles.

181. FE5 stated that whenever SCE has a problem of any kind involving its distribution system, the incident is reported and uploaded into an internal database as a Preliminary Incident Report (or "PRI"). FE5 was tasked with monitoring PRIs and assigning the incidents to a team of incident investigators for further action.

182. FE5 disclosed that SCE received multiple reports of "down wires" daily. Causes of down wires include utility poles falling over often due to rot, the arms of a utility pole breaking off, the wire itself breaking due to age, the wire detaching from the fuse on the pole, and two wires touching each other to cause a short and spark that breaks both.

183. FE5 specially cited down wires as a fire hazard, and recalled that that downed wires caused a few fires a month, and some of those fires spread.

184. FE5 further recalled that investigators made repeated recommendations for actions to take to prevent the problem from occurring again, such as the replacement of aging equipment, poles or wire. The recommendations were memorialized in reports and sent to members of management including Greg McDonald, Director of Safety, Antillon, and Klugian.

185. These recommendations were usually not implemented, according to FE5; instead, SCE deployed stopgap measures such as using a "splitter" to connect the two broken pieces of wire back together.

Edison Runs its Equipment to Failure

186. SCE's maintenance failures were compounded by its overall approach to infrastructure maintenance. FE5 characterized SCE's maintenance program for its distribution system as "deal with it when it breaks."

187. In its 2015 GRC, SCE indicated its adherence, at least in part, to "run-to failure" maintenance practices. Under this model, SCE "deal[s] with equipment as it wears out" by "wait[ing] until the equipment fails in service and then replac[ing] it[.]"[50]

---

[50] SCE, 2015 General R ate Case Application, Workpapers, Transmission & Distribution Infrastructure Replacement Programs, SCE-03 Volume 04 at 1 (Nov. 2013), publicly-available at:

188. SCE explained its reliance on run-to-failure as follows: "A run-to-failure strategy can, for some types of equipment, be the preferred approach. For equipment whose in-service failures have minimal consequences, there is little benefit derived from preemptive replacement."[51]

189. Also in the 2015 GRC, SED identified "run to failure" as one of three options deployed by SCE with respect to replacing equipment.[52]

190. SCE, however, did not clarify precisely *what* equipment would be included in the failure-with-minimal consequences category, or what "minimal consequences" even means.

191. For example, SCE, in the same document, repeatedly cites oil-filled transformers as having the potential to cause fires, but does not attribute the same risks to utility pole failure.[53] Likewise, SCE describes energized conductors as "serious fire hazard" while going on to mention vegetation in the following sentence without describing vegetation as a fire hazard at all.[54]

192. SCE's reliance on the run-to-failure option exemplifies the mentality that SED warned of in the 2015 GRC, when it noted that "subjective nature" of SCE's approach "to both the risks presented and the determination of 'acceptable level' down to which the risks can be mitigated." Accordingly, SED suggested that "[t]he more that SCE can use data to support its future proposals, the less subjectivity in balancing risk

---

http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/281B011D6173DA7288257C220075395B/$FILE/APP%20SCE-03%20Vol.%2004.pdf

[51] *Id.* at 2.

[52] CPUC/SED, Aug. 15, 2014 Staff Report at 28.

[53] *Id.* at 72, 77.

[54] *Id.* at 60.

trade-offs will occur."[55]

193. FE6, a former CPUC investigator, agreed that SCE let equipment run until it broke, *i.e.*, the "run to failure or RTF" maintenance program. FE6 further noted that SCE sometimes didn't know when electrical equipment was installed on its poles.

194. In the wake of the Woolsey Fire, SCE was hit with multiple lawsuits alleging that its run-to-failure protocol was a direct cause of the fire.

195. Specifically, it was alleged that (a) in 2015, SCE identified a power pole at Koenigstein Road, the source of the ignition of the Thomas Fire, as needing to be replaced; (b) despite identifying the need, SCE chose not to replace the pole and let it run to failure: (c) the dilapidated power pole that SCE ignored years earlier foreseeably failed, causing an explosion and a shower of sparks that ignited the Thomas Fire; and (d) per its run-to-failure protocol, immediately after the Thomas Fire, SCE finally came to Koenigstein Road and replaced the pole. These allegations were leveled despite the fact that the plaintiffs in these lawsuits pled no damages relating to the Thomas Fire.

196. The lawsuits also argued that by implementing the run-to-failure model and other improper practices, SCE failed to conduct appropriate, timely equipment inspections and maintenance in violation of CPUC regulations, and that preventative inspections and maintenance would have prevented the start of the Woolsey Fire.

<u>Edison's Deficient Risk Assessment Practices</u>

197. In January 2017, when SED evaluated Edison's 2018 GRC application, the regulatory agency was highly critical of Edison's risk assessment practices, determining it would be "unwise to accept Edison's risk assessment methods as a basis

[55] CPUC/SED, Aug. 15, 2014 Staff Report at 9.

for determining reasonableness of safety-related program requests."[56]

198. SED found that that "Edison is classifying major categories of spending as safety related, even though they relate to issues of customer satisfaction or electric service reliability than safety."

199. For example, SED found that found that "[w]hile Edison projected improvements in reliability metrics in its testimony from grid modernization, SED did not find that Edison had provided similar projection in terms of improvement in safety metrics." Ultimately, SED concluded that "[g]rid modernization funding requests compete with traditional safety related programs for funding, ***such as prioritized aging infrastructure replacement***." (Emphasis added).

200. Edison also "admitted in testimony that it did not use risk assessment in the identification of its top risks, or to select programs to address those risks, but mostly after-the-fact as a way to measure risk reduction associated with the programs or projects proposed."

201. Perhaps most alarmingly for one of the nation's largest electric utilities in a region affected by increasingly severe wildfires, "SCE's approach to identify threats or risk drivers suffers from an almost non-existent level of granularity" leading to "SCE's current risk-informed decision-making process" being deemed "too immature … to allow [for] meaningful analysis [.]"

202. In sum, SED found that the high risk scores of Edison's infrastructure showed that Edison's current methodology did not prioritize safety. SED determined that Edison needed to make substantial improvements in evaluating and characterizing the risk of its infrastructure.

---

[56] http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Risk_Assessment/SCE%202018%20GRC%20Report%20Final%20with%20Appendix%20A.pdf

203. SCE's methods of determining risk "underestimate[d] both the frequency and consequence/impact of very low frequency and very high consequence events, ***such as highly catastrophic wildfires***. This is particularly true where Edison is relying on historical data as a basis for estimating the frequency and consequence terms." Edison was not even able to "provide even a qualitative prioritization of its risks." (Emphasis added).

204. Throughout the Class Period, Edison continued to obsessively prioritize grid modernization in lieu of aged infrastructure remediation, while not making any substantial improvements in evaluating and characterizing the risk of its infrastructure, as SED strongly recommended.

Edison Lobbies for Ratepayers to Indemnify its Fire-Related Liability

205. In 2009, San Diego Gas & Electric ("SDG&E") – one of three California power monopolies along with SCE and Pacific Gas & Electric ("PG&E") – sought permission from CPUC to charge customers almost $400 million in leftover costs from the 2007 Guejito, Rice, and Witch Fires, where damages totaled more than $2 billion, an amount far in excess of PG&E's available insurance.

206. After SDG&E's attempt to insulate itself from liability was rejected by CPUC and failed in court, lobbyists for the monopolies began to press for a legislative iteration of the proposal.

207. Long before the start of the Class Period, it was thus apparent to Edison and other California utilities that disclosure of fire-related malfeasance could result in far-ranging negative financial consequences.

208. In the years leading up to the passage of SB 901 in August 2018, it was reported that PG&E, SCE and SDG&E spent more than $17 million lobbying

legislators for relief from wildfire damages.[57]

209. SB 901, in part, allows power companies to issue bonds to pay for future wildfire-related expenses, and if regulators determine that utilities met the prevention standards in their fire mitigation/prevention plans and other rules, *i.e.,* were not negligent, they will be allowed to pass the bond costs on to their customers.

210. In particular, SB 901 allows a utility, with regulators' approval, to impose a special fee on customers to pay such costs related to wildfires ("rate recovery").

211. Under the Prudent Manager Standard, a utility has the burden to affirmatively prove that it reasonably and prudently operated and managed its system. That means a utility must show that its actions, practices, methods, and decisions show reasonable judgment in light of what it knew or should have known at the time, and in the interest of achieving safety, reliability, and reasonable cost.

212. If, under the Prudent Manager Standard, the utility is found to have acted negligently, the utility must absorb costs in excess of the utility's insurance.

213. In regulatory proceedings, decided in July 2018, involving SDG&E's request for rate recovery with respect to the 2007 fires, SCE expressly argued that rate recovery should not be used to deter imprudent actions.[58]

214. Regardless, SB 901 did not nullify the governing legal doctrine of inverse condemnation, which holds that when private company like a utility is given access to private property for its equipment, they are responsible for any damage that equipment

---

[57] John Myers, "One small change to California's wildfire prevention law could spark a huge political fight in Sacramento," *Los Angeles Times* (Dec. 3, 2018), publicly-available at: https://napavalleyregister.com/news/local/one-small-change-to-california-s-wildfire-prevention-law-could/article_974129ff-380a-5121-83ee-731374305278.html

[58] *See* Order Denying Rehearing of Decision (D.) 17-11-033 (July 13, 2018), publicly-available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M218/K019/218019946.PDF

causes.

215. Wildfire liability is of existential importance for California utilities: PG&E, with service territory in Northern California, filed for Chapter 11 reorganization on January 29, 2019 in the aftermath of the 2017 and 2018 wildfire seasons, the two most destructive in state history. PG&E cited up to $30 billion in liabilities since many blazes, including the 2018 Camp Fire, have been linked to its equipment.

216. SCE has already seen its credit rating downgraded twice by credit ratings agencies in 2019, leaving it "near the bottom of the investment grade category," and in need for a higher rate of return in order to attract necessary capital.[59] SCE recently requested that the Federal Energy Regulatory Commission ("FERC") include an upward adjustment for SCE's extraordinary wildfire risk in the authorized return on equity (ROE) for the portion of SCE's business regulated by FERC.[60]

217. SCE's ROE request cited "dramatic material changes to SCE's regulatory and financial conditions" since October 2017 – just prior to the Thomas Fire – and underscores the extent to which the SCE Defendants were able to maintain inflated stock prices throughout the Class Period by concealing the fire risks that were the logical result of their inadequate infrastructure maintenance.

Edison Causes the Thomas Fire

218. On October 20, 2017, Cal Fire issued a news release to warn of

[59] *See* Robert Walton, "Southern California Edison requests higher ROE, citing wildfire risks," *Utility Dive* (April 12, 2019), publicly-available at: https://www.utilitydive.com/news/southern-california-edison-requests-higher-roe-citing-wildfire-risks/552577/

[60] *Id.*

dangerous weather conditions in Southern California following the devastating Northern California fires. Cal Fire specifically said:

> After one of the deadliest and most destructive weeks in California's history, firefighters are preparing for another significant wind event in Southern California. The National Weather Service has issued several Red Flag Warnings and Fire Weather Watches across Southern California starting this weekend through early next week due to gusty winds, low humidity and high temperatures. In response to these anticipated conditions, CAL FIRE is increasing its staffing levels with additional firefighters, fire engines, fire crews, and aircraft to respond to any new wildfires. **"This is traditionally the time of year when we see these strong Santa Ana winds," said Chief Ken Pimlott, director of CAL FIRE.** "And with an increased risk for wildfires, our firefighters are ready. Not only do we have state, federal and local fire resources, but we have additional military aircraft on the ready. Firefighters from other states, as well as Australia, are here and ready to help in case a new wildfire ignites." The weather warnings stretch from Santa Barbara, San Diego, Orange, Riverside, Los Angeles, San Bernardino and Ventura counties. **The winds are expected to reach gusts of up to 50 mph, along with record breaking heat, fire danger in these areas is high.** It is vital that the public use caution and avoid activities that may spark a new fire. **Any new fires can spread rapidly under these types of weather conditions.**

219. On December 4, 2017, the National Weather Service issued a "Red Flag Warning" which stated, "[t]his will likely be the strongest and longest duration Santa Ana wind event we have seen so far this season. If fire ignition occurs, there will be the potential for very rapid spread… and extreme fire behavior."[61]

220. The National Weather Service issues Red Flag Warnings to alert fire departments and the public of the onset, or possible onset, of critical weather and dry conditions that could lead to rapid or dramatic increases in wildfire activity. A Red

---

[61] Sonali Kohli, Expect the "Strongest and Longest" Santa Ana Winds of the Season this Week in L.A. Area," *Los Angeles Times* (Dec. 4, 2017 8:10 a.m.), http://www.latimes.com/local/lanow/la-me-ln-fire-risk-20171204-story.html

Flag Warning is issued for weather events that may result in extreme fire behavior that will occur within 24 hours. A Red Flag Warning is the highest alert. During these times, extreme caution is urged because a simple spark can cause a major wildfire.[62]

221. Edison ignored the Red Flag warning, and did not de-energize facilities, despite having the ability to do so, *see* ¶92 above, even though SDG&E submitted de-energization reports to CPUC during the same period.

222. That same day, the Thomas Fire – which ignited during Santa Ana wind conditions – burned more than 280,000 acres and destroyed 1,063 structures in Ventura and Santa Barbara Counties. The Thomas Fire also caused widespread power outages, road and school closures, and forced thousands of residents to be evacuated and local businesses to be shut down. It was, at the time, the largest fire by acreage in state history.

223. Multiple witnesses attested to seeing an SCE transformer on a utility pole located on Koenigstein Road explode, sending a shower of sparks nearby.[63]

224. The Thomas Fire also triggered mudslides in its burn area on January 9, 2018, resulting in twenty-two (22) deaths, including children, and was not fully contained until January 12, 2018.

225. Almost a year later, in late October 2018, Edison admitted that its electrical equipment was "associated with" at least one of the two points of origin of the Thomas Fire.

226. Defendant Pizarro elaborated on the finding in an earnings conference

---

[62] *Red Flag Warnings & Fire Weather Watches*, Cal. Dept. Forestry & Fire Protection, http://calfire.ca.gov/communications/communications_firesafety_redflagwarning

[63] Kit Stolz, "Thomas Fire Had Two Origins," Santa Barbara Independent (Dec. 22, 2017), publicly-available at: https://www.independent.com/2017/12/22/thomas-fire-had-two-origins/

call with investors, stating that the Company expected to "incur material losses" from the Thomas Fire.

227. In March 2019, CPUC and county investigators a publicly released a seventy (70)-plus page report announcing that "[t]he IT's O&C, Intel, [and] collection and evaluation of evidence concluded that the power lines owned and operated by SCE were the cause of the THOMAS fire."[64]

228. The investigation of the fire's origins found that high winds blew Edison power lines into one another, creating an electrical arc that "deposited hot, burning or molten material" into dry vegetation on the ground, setting off the blaze.

229. Investigators cited several possible criminal violations by Edison in connection with the fire, including ***involuntary manslaughter***, ***reckless arson*** and a health-safety code breach for carelessly or negligently causing a fire.

230. The investigators also flagged a violation of GO 95's requirement that "[e]lectrical supply and communication systems … shall be maintained in a condition which will enable the furnishing of safe, proper and adequate service."

231. According to the report, the blaze started in two spots and eventually merged into one fire. One was in a canyon above Steckel Park in the Santa Paula area and where first responders were sent when the blaze broke out at about 6:30 p.m. Dec. 4, 2017. The second spot was on Koenigstein Road near Highway 150, discussed above in connection with Edison's "run-to-failure" policy and practice.

232. The investigative team determined, based on physical evidence, that the power lines associated with both ignition points were connected to the same circuit (the "Castro Circuit").

[64] *See* https://vcfd.org/images/news/Thomas-Fire-Investigation-Report_Redacted_3-14-19.pdf

233. During meetings between investigators and SCE representatives on December 27, 2017, SCE claims investigators Rick McCollum and Julie Olin confirmed the identity of SCE's Castro Circuit, and further reported that at 6:41 p.m. on December 4, SCE's substation reported a remote automatic recloser alert to its system.

234. Investigators observed "***several areas where SCE equipment failed***. The power lines were inspected within the [fire outbreak area] and determined by the [investigative] to have had phase to phase contact on several spans of power lines." (Emphasis added).

235. Data collected by investigators "showed a power interruption associated with SCE equipment on Monday, December 4, 2017, at approximately 6:17 PM." This data was corroborated by several pieces of video imagery also collected by the investigators.

236. As of mid-March 2019, several thousand plaintiffs had already filed Thomas Fire-related lawsuits naming, among others, Edison and SCE, and the deadline for future suits is years away.

237. The Thomas Fire alone has left SCE exposed to liability of billions of dollars in damages.

Edison Causes the Woolsey Fire

238. In May 2016, CPUC adopted Fire Map 1, which "depicts areas of California where there is an elevated hazard for ignition and rapid spread of power line fires due to strong winds, abundant dry vegetation, and other environmental conditions."[65] As of January 19, 2018, the area in and around the Woolsey Fire was

[65] National Association of Regulatory Utility Commissioners,"California: CPUC Fire Map Depicts Areas of Elevated Hazards in State; First Step In Creation of Tools to Help Manage Resources" (May 26, 2016), publicly-available at:

color-coded red, indicating "a very high risk of a devastating wildfire."[66]

239. Following the Thomas Fire, on July 12, 2018, CPUC adopted Resolution ESRB-8, which ordered utilities to engage local communities in developing de-energization programs. ESRB-8 further required that utilities submit a report within ten (10) days after each de-energization event, and after high-fire-threat events where the utility provided notifications to local government, agencies, and customers of possible de-energization, even where no de-energization occurred.

240. Aside from ESRB-8, Edison was made aware of the risks of failing to de-energize on July 13, 2018, when CPUC affirmed its denial of SDG&E's request to pass on $379 million in 2007 wildfire-related costs to ratepayers, based, in part, on SDG&E's failure to timely de-energize its lines. SCE was a party to those proceedings.

241. Two days before the start of the Woolsey fire, Edison had activated its emergency operations center and advised customers that it could proactively shut off power as a safety measure due to the windy weather and a Red Flag fire warning. Meteorologists with the National Weather Service had warned that a fire could spread rapidly because of gusty winds, low humidity, and "critically dry fuels," including brush and vegetation.

242. The SCE Defendants, without question, knew about the Red Flag Warning. In fact, SCE retweeted the National Weather Service warning on November 7 – one day before the Woolsey Fire began.

243. The SCE Defendants further knew that a disproportionate number of

https://www.naruc.org/bulletin/the-bulletin-053116/california-cpuc-fire-map-depicts-areas-of-elevated-hazards-in-state-first-step-in-creation-of-tools-to-help-manage-resources/

[66] ftp://ftp.cpuc.ca.gov/safety/fire-threat_map/2018/PrintablePDFs/8.5X11inch_PDF/CPUC_Fire-Threat_Map_final.pdf

Edison utility poles requiring replacement were those with higher wind loading conditions.

244. Ultimately, Edison elected not to de-energize its lines: a review of Utility De-Energization Reports archived on CPUC's website does not show any submissions by SCE prior to December 29, 2018, nearly two months after the Woolsey Fire began.[67]

245. The Woolsey Fire started on November 8 in Simi Valley near the Rocketdyne facility in the Santa Susana Pass at approximately 2:24 p.m. The Rocketdyne facility, which was the site of a partial nuclear meltdown in 1959, has been called "one of the most contaminated sites in the country" thus heightening the stakes of Edison's already risky conduct.[68]

246. According to CPUC, SCE's Chatsworth substation is located "within the larger Boeing Rocketdyne Santa Susana complex," as depicted in the below, pre-fire Google Earth image:

[67] *See* http://cpuc.ca.gov/deenergization/. Subsequently, in 2019, local media reported that June 20, 2019 marked "the first time SoCal Edison used its public safety power shut off plan to reduce the risk of wildfires caused by downed power lines." *See* https://losangeles.cbslocal.com/2019/06/21/socal-edison-public-safety-power-outages/.

[68] https://la.curbed.com/2018/11/12/18089298/woolsey-fire-santa-susana-field-lab-rocketdyne

247. The Chatsworth substation is located at E Street and Alfa Road in Ventura County, which is also where Cal Fire says the Woolsey Fire ignited.

248. An incident report from the Ventura County Fire Department states that firefighters arriving at the scene at 2:42 p.m. made contact with the Rocketdyne officer who stated that there were two fires. When asked what started the fires, the Rocketdyne officer stated "[p]ower lines."

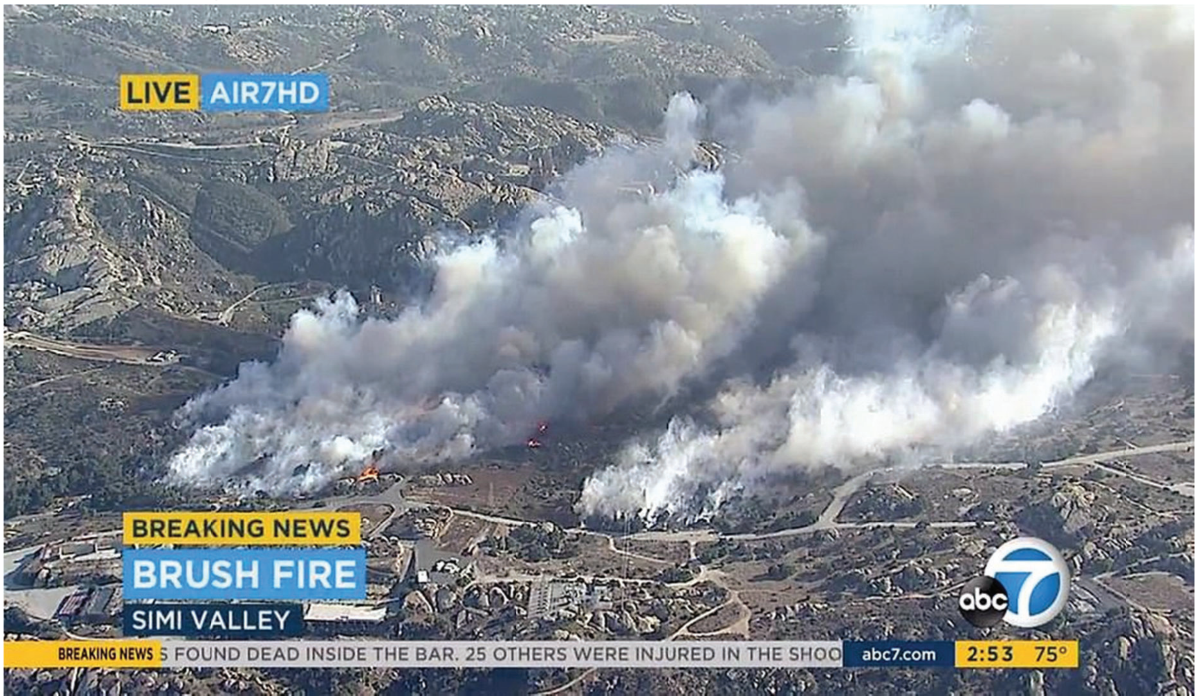
249. In addition, the individual who initially called in the fire was Dirk Delong Obenshain ("Obenshain"), an electrician with Contra Costa Electric ("Contra Costa"), based out of their Bakersfield, California, location. Contra Costa is a contractor for SCE. In connection with Plaintiffs' investigation, Mr. Obenshain confirmed that he reported the fire at the Santa Susana Field Lab, also known as RocketDyne site.

250. When asked where he was located when he saw and reported the fire, Mr. Obenshain said he was at the site. He continued and said that he was at the site as an

electrician working at SCE's substation located at the site.

251. "We were working out there," Mr. Obenshain stated, "The fire started when we were out there."

252. A newscast aerial view reporting the start of the Woolsey Fire documents its beginnings directly under SCE's 16Kv power poles, with the Chatsworth substation visible in the foreground:



253. The Ventura County Fire Department's Detailed Incident Report of the Woolsey Fire shows that at 5:59 p.m. – more than three hours after the fire was reported by one of its own contractors – Edison had begun to de-energize power in fire-affected area. This is consistent with the reactive, "after-the-fact" approach to risk management that SED had previously cautioned the Company about. *See* ¶200 above. It also virtually replicated SDG&E's failure to de-energize for almost 2.5 hours after it knew the Witch Fire had started, a decision that Edison knew had exposed SDG&E to catastrophic financial losses. *See* ¶240 above.

254. At 8:12 p.m. on November 8, 2018, or nearly six hours after the start of

the fire, SCE sent an "Electric Safety Incident Report" to CPUC stating that the Chatsworth substation suffered an outage at the "big Rock 16kV circuit" at 2:22 p.m., two minutes before the Woolsey Fire began.[69]

255. Driven by the same powerful Santa Ana winds that gave rise to the November 6, 2018 Red Flag Warning, the Woolsey Fire quickly engulfed over 98,000 acres in Ventura and Los Angeles counties.

256. The fire incinerated over 1,600 structures and damaging hundreds of others, forced as many as 250,000 people to flee their homes, and resulted in the deaths of three civilians, as well as injuries to three firefighters. According to Cal Fire, the Woolsey Fire burned 83 percent of all National Parks Service land in the Santa Monica Mountains National Recreation Area.

257. The Woolsey Fire was not fully contained until November 21, 2018.

258. Approximately two weeks later, SCE released a public statement[70] and submitted a supplemental letter[71] to CPUC acknowledging equipment failures in greater detail near the origin point of the Woolsey Fire.

259. In particular, SCE's letter to CPUC revealed that "SCE's first responding troubleman [*i.e.*, the person who actually goes out to physically check the power grid

---

[69] *See* Electric Safety Incident Reported- Southern California Edison Incident No.: 181108-9003, CPUC (Nov. 8, 2018 8:12 P.M.), publicly-available at https://www.edison.com/content/dam/eix/documents/Woolsey_Electric_Safety_Report .pdf

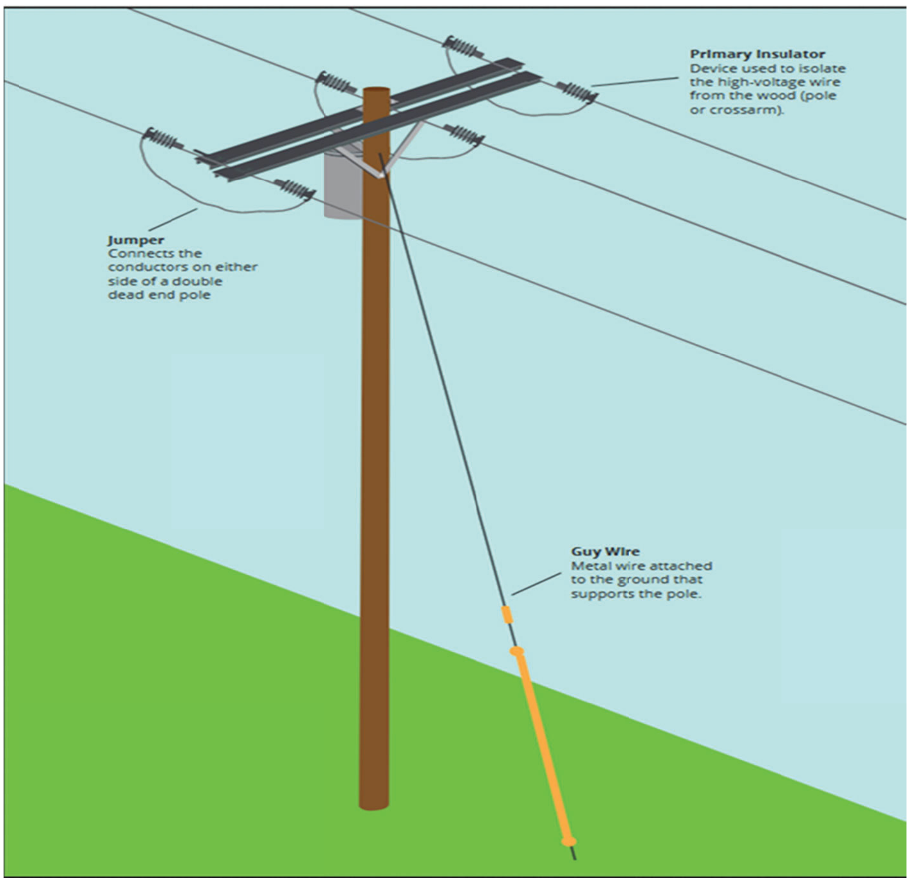
[70] SCE, Press Release, "SCE Publicly Releases CPUC Submission on the Woolsey Fire," (Dec. 12, 2018), publicly-available at: https://www.businesswire.com/news/home/2018120

6005977/en/SCE-Publicly-Releases-CPUC-Submission-Woolsey-Fire

[71] Letter from Robert Ramos, Director of Risk and Claims Management, SCE, to SED (Dec. 6, 2018), publicly-available at: https://www.edison.com/content/dam/eix/documents/woolsey_letter_to_cpuc.pdf.

and its connections to its power source] conducted a patrol to evaluate the operational status of its facilities and found no wire down on the 16kV circuit. SCE subsequently found a guy wire in proximity to a jumper at a lightweight tubular steel pole,"[72] meaning that the guy wire, a tensioned cable, was less than eight feet from the jumper and less than six feet from the pole.[73]

260. The guy wire was found on the ground, having failed, and no longer providing support to the intended structure. The following graphic created by Edison depicts a functioning guy wire:



---

[72] *Id.*

[73] CPUC, State of California Rules for Overhead Electric Line Construction, General Order No. 95 at II-12, II-13, V-52 (Jan. 2015), publicly-available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M146/K646/146646565.pdf.

[Guy Wire, Southern California Edison][74]

261. SCE's press release further stated that "the potential that the Nov. 8 outage was related to contact being made between the guy wire and the jumper remains under review by SCE," as well as "several additional areas of focus."[75]

262. Previously, as of March 2016, SCE had identified more than 2,600 guy wires with noncompliant safety factors.[76]

263. On April 25, 2019, Los Angeles County announced it had filed a lawsuit against SCE to recover costs in connection with the Woolsey Fire.

264. On August 30, 2019, in the course of civil litigation against SCE over the Woolsey Fire, it was revealed that the California Attorney General's Office was in the process of conducting a criminal investigation into the cause and origin of the fire.

265. The criminal investigation became public when the California Attorney General's Office moved to block subpoenas for documents related to the investigation into the Woolsey Fire, arguing that disclosure of the documents would jeopardize the ongoing criminal investigation, which had already been pending for nine (9) months.

266. By late September 2019, the California state court overseeing Woolsey Fire-related civil litigation against SCE had been persuaded to subject the investigative report to a protective order.

267. While a redacted version of the report was made available to attorneys in the civil litigation, including SCE's attorneys, the redacted report cannot be shared with the attorneys' clients, consultants or the public.

268. The court said that the full report would be released in April 2020.

---

[74] https://www.edison.com/content/dam/eix/documents/guywire.pdf

[75] https://www.businesswire.com/news/home/2018120

[76] SCE, General Rate Case 2018, T&D Vol. 9, Poles at 16 n.26.

269. On November 13, 2019, SCE agreed to pay $360 million to settle claims with twenty-three (23) cities and counties impacted by the Thomas Fire, its resultant mudslides, and/or the Woolsey Fire, including Santa Barbara, Ventura and Los Angeles Counties, as well as the cities of Santa Barbara, Malibu, Calabasas, Thousand Oaks, and Westlake Village.

Materially False and Misleading Statements Issued During the Class Period[77]

2015 10-K

270. The Class Period begins on February 23, 2016, when the Company filed its annual statement on Form 10-K for the fiscal year ending December 31, 2015 (the "2015 10-K"). The 2015 10-K was signed by Defendants Craver, Pizarro, Scilacci, and Rigatti.

271. In the 2015 10-K, the Company touted its investment in the safety of its equipment, stating that "***SCE is investing in and strengthening its electric grid and driving operational and service excellence to improve system safety, reliability and service*** while controlling costs and rates."

272. The statements referenced in ¶271 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (iv) the Company failed to utilize a statistically-valid methodology to evaluate

[77] Emphasis added throughout, unless otherwise noted.

pole-loading; (v) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vi) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (vii) the Company failed to properly assess the risks of its equipment; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) consequently, the Company was in violation of state law and regulations; (x) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xi) as a result, the Company's public statements were materially false and misleading at all relevant times.

273. The 2015 10-K discussed Edison's purported infrastructure investment program, as well as the risks posed to the Company's financial condition and operations by its failure to remediate aging infrastructure, stating in relevant part:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates the operational risks and the need for superior execution in its activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous***. SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

274. The statements referenced in ¶273 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and

compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company failed to replace or reinforce aging and unsafe utility poles and/or attached wires, resulting in fire incidents; (ii) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments – including assessments of age-deteriorated poles – than were actually needed; (iii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment aging and consequent failure; (iv) the Company failed to assess, remediate, repair, and/or replace aging poles as prescribed by CPUC; (v) the Company failed to properly assess the risks of its aging equipment; (vi) consequently, the Company was in violation of state law and regulations; and (vii) as a result, the Company's public statements were materially false and misleading at all relevant times.

275. In addition, the risk factors referenced in ¶273 above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, the SCE Defendants had already caused July-August 2015 Long Beach outages, which affected to 30,000 customers, caused fires in several underground structures, and resulted in explosions that blew manhole covers into the air. Moreover, the SCE Defendants knew their claimed infrastructure investments were insufficient to mitigate the cited risks for the reasons described in ¶274 above.

276. The SCE Defendants acknowledged in 2015 10-K that their business may result in damage to private and public property, as well as injuries to bystanders, stating in relevant part:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***
>
> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through

> downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant.*** The CPUC has increased its focus on public safety issues with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations***.

277. The risk factors referenced in ¶276 above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, the SCE Defendants had already (i) failed to maintain electrical equipment that injured three U.S. Marines in Twentynine Palms in 2015; (ii) caused the Potrero Fire of November 2015, in which the Company was cited for failing to replace or reinforce an unsafe utility pole; and (iii) been fined $50,000 on February 12, 2016, prior to the filing of the 2015 10-K, for the fatal electrocution at Edison's Whittier facility. More specifically, the SCE Defendants knew their potential liability extended well beyond "inherent risks" to include risks created by the Company's own reckless disregard of safety, as described in ¶274 above.

278. Relatedly, the 2015 10-K discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

> ***SCE's insurance coverage for wildfires arising from its ordinary operations may not be sufficient.***
>
> Edison International has experienced increased costs and difficulties in obtaining insurance coverage for wildfires that could arise from SCE's ordinary operations. In addition, the insurance that has been obtained for wildfire liabilities may not be sufficient. Uninsured losses and increases in

> the cost of insurance may not be recoverable in customer rates. A loss which is not fully insured or cannot be recovered in customer rates could materially affect Edison International's and SCE's financial condition and results of operations. Furthermore, insurance for wildfire liabilities may not continue to be available at all or at rates or on terms similar to those presently available to Edison International.
>
> * * *
>
> *Wildfire Insurance*
>
> Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Prolonged drought conditions in California have also increased the risk of severe wildfire events***. On June 1, 2015, Edison International renewed its liability insurance coverage, which included coverage for SCE's wildfire liabilities up to a $610 million limit (with a self-insured retention of $10 million per wildfire occurrence). Various coverage limitations within the policies that make up this insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy period (June 1, 2015 to May 31, 2016). SCE also has additional coverage for certain wildfire liabilities of $390 million, which applies when total covered wildfire claims exceed $610 million, through June 14, 2016. SCE may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.

279. The risk factors referenced in ¶278 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically, the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or prolonged drought conditions to include risks created by the

Company's own reckless disregard of safety, as described in ¶274 above.

280. The 2015 10-K discussed a prior incident where its equipment malfunctioned and caused multiple fires in Long Beach, California:

> ***In July 2015, SCE's customers who are served via the network portion of SCE's electric system in Long Beach, California experienced service interruptions due to multiple underground vault fires and underground cable failures***. No personal injuries have been reported in connection with these events. SCE instituted an internal investigation and commissioned an external investigation of these events and their causes***, which revealed that the main cause of the interruptions was a lack of adequate management oversight of the downtown network system. The investigations also revealed deficiencies in maintaining the knowledge base on the configuration and operation of the system, and a lack of sophisticated controls needed to more efficiently and effectively prevent and respond to the cascading events that occurred.***

281. The statements referenced in ¶280 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) The Long Beach outages affected not only those customers served by Edison's Long Beach secondary network, but at times extended to 30,000 customers, including customers who receive their power from radial circuits that also feed the secondary network, and thus Edison downplayed the systemic risks of its safety violations; (ii) the Company failed to replace or reinforce aging and unsafe electrical infrastructure, resulting in fire incidents; (iii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment aging and consequent failure; (iv) the Company's noncompliant electricity networks created a significantly heightened fire risk; (v) the Company failed to properly assess the risks of its equipment; and (vi) as a result, the Company's public statements were

materially false and misleading at all relevant times.

May 2, 2016 Press Release

282. On May 2, 2016, the Company issued a press release filed on Form 8-K with the SEC entitled "Edison International Reports First Quarter 2016 Results; Reaffirms 2016 Earnings Guidance," in which Defendant Craver stated, in part: "At SCE, we continue to see significant rate base growth driven by ***continued investment in infrastructure reliability and public safety*** ...."

283. The statements referenced in ¶282 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (iv) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (v) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vi) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (vii) the Company failed to properly assess the risks of its equipment; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) consequently, the Company's conduct created material risks to public safety, system integrity, and Edison's rate base growth; (x) the Company conflated electric service reliability and safety; and (xi) as a result, the Company's public statements were materially false and misleading at all relevant times.

Q1 2016 10-Q

284. That same day, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q1 2016 10-Q"). The Q1 2016 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

> *Wildfire Insurance*
>
> Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Prolonged drought conditions in California have also increased the risk of severe wildfire events.*** On June 1, 2015, Edison International renewed its liability insurance coverage, which included coverage for SCE's wildfire liabilities up to a $610 million limit (with a self-insured retention of $10 million per wildfire occurrence). Various coverage limitations within the policies that make up this insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy period (June 1, 2015 to May 31, 2016). SCE also has additional coverage for certain wildfire liabilities of $390 million, which applies when total covered wildfire claims exceed $610 million, through June 14, 2016. ***SCE may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.***

285. The risk factors referenced in ¶284 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically, the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or prolonged drought conditions to include risks created by the Company's own reckless disregard of safety, as described in ¶283 above.

286. In the Q1 2016 10-Q, the Company stated that:

> Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this MD&A and in Edison International's and SCE's combined 2015 Form 10-K, including the "Risk Factors" section. ***Readers are urged to read this entire report, including the information incorporated by reference, as well as the 2015 Form 10-K, and carefully consider the risks, uncertainties and other factors that affect Edison International's and SCE's businesses***.

287. As discussed above, in the 2015 10-K, the Company discussed the following risk factors, in addition to wildfire insurance:

a) Failure to remediate aging infrastructure:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates the operational risks and the need for superior execution in its activities***. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous. SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

b) Damage to private and public property:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***
>
> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant.*** The CPUC has

increased its focus on public safety issues with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

288. The risk factors referenced in ¶287(a) above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶275 above.

289. The risk factors referenced in ¶287(b) above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶277 above.

Q2 2016 10-Q

290. On July 28, 2016, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q2 2016 10-Q"). The Q2 2016 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

Wildfire Insurance

Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Prolonged drought conditions in California have also increased the duration of the wildfire season and the risk of severe wildfire events.*** SCE

> has approximately $910 million of third party insurance coverage for wildfire liabilities for the period from July 2016 to May 2017. SCE's program includes approximately $90 million in self-insurance at various levels within the $910 million of third party insurance coverage, which combined, equals approximately $1 billion. In addition, SCE has a self-insured retention of $10 million per wildfire occurrence. ***SCE may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.***

291. The risk factors referenced in ¶290 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically, the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or prolonged drought conditions to include risks created by the Company's own reckless disregard of safety.

292. In the Q2 2016 10-Q, the Company stated that:

> Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this MD&A and in Edison International's and SCE's combined 2015 Form 10-K, including the "Risk Factors" section. ***Readers are urged to read this entire report, including the information incorporated by reference, as well as the 2015 Form 10-K***, and carefully consider the risks, uncertainties and other factors that affect Edison International's and SCE's businesses.

293. As discussed above, in the 2015 10-K, the Company discussed the following risk factors, in addition to wildfire insurance:

a) Failure to remediate aging infrastructure:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates the operational risks and the need for superior execution in its activities***. SCE's financial condition and results of operations could be

materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous. SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

b) Damage to private and public property:

The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.

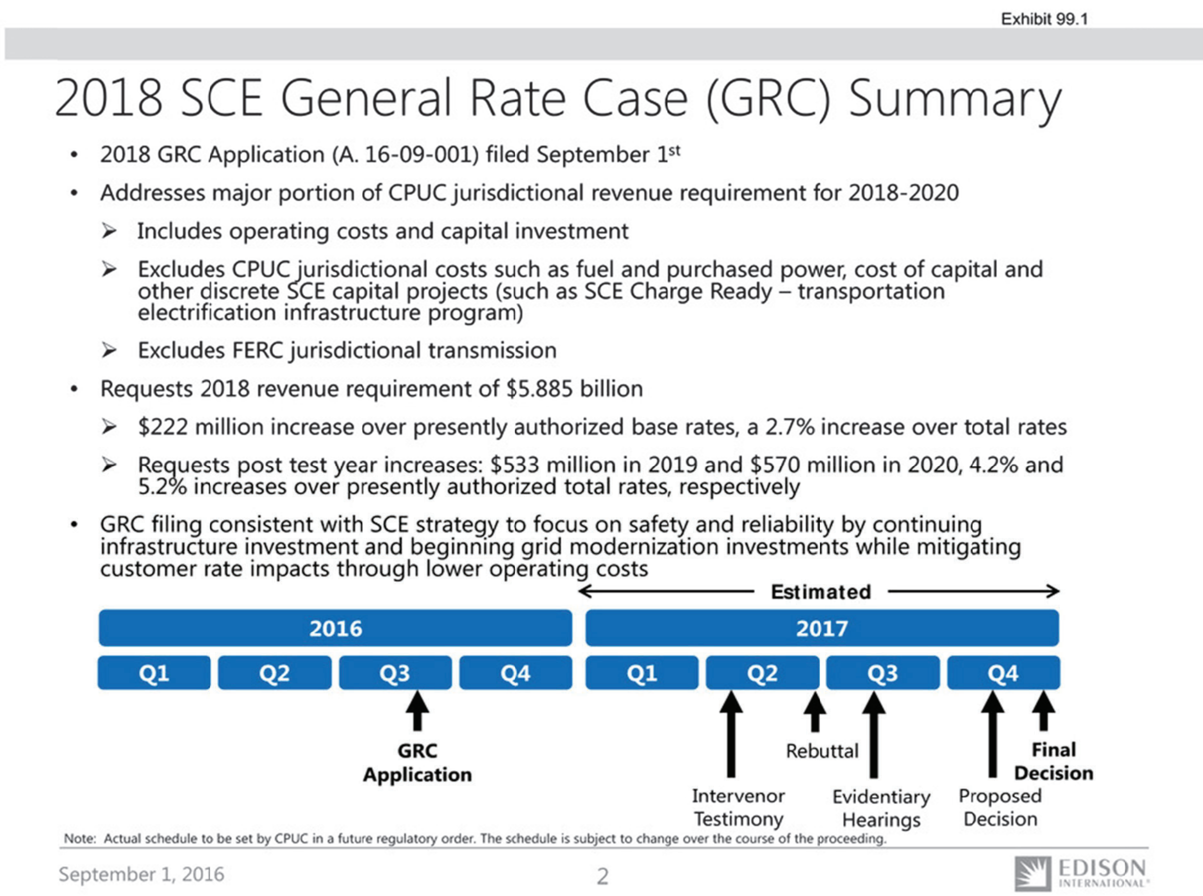
Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant.*** The CPUC has increased its focus on public safety issues with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

294. The risk factors referenced in ¶293(a) above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶275 above.

295. The risk factors referenced in ¶293(b) above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as in ¶277 above.

2018 SCE General Rate Case Overview

296. On September 1, 2016, the Company filed a presentation on Form 8-K with the SEC – entitled "2018 SCE General Rate Case Overview" – which included the following slide purporting to summarize the Company's 2018 GRC, including the claim that Edison's 2018 GRC filing was "consistent with SEC strategy focusing on safety and reliability by continuing infrastructure investment and beginning grid modernization investments ….":



297. The statements referenced in ¶296 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and

compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (iv) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (v) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vi) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (vii) the Company failed to properly assess the risks of its equipment; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) consequently, SCE's 2018 GRC filing was not "consistent" with any pre-existing "focus on safety"; (x) the Company conflated electric service reliability and safety; and (xi) as a result, the Company's public statements were materially false and misleading at all relevant times.

November 1, 2016 Press Release

298. On November 1, 2016, the Company issued a press release filed on Form 8-K with the SEC entitled "Edison International Reports Third Quarter 2016 Results; Reaffirms 2016 Earnings Guidance," in which Defendant Pizarro stated, in part: "We continue to see a long-term opportunity for above-average earnings and dividend growth based on ***SCE infrastructure replacement and electric grid modernization*** .."

299. The statements referenced in ¶298 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading

statements and/or failed to disclose that: (i) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (ii) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (iii) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (iv) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (v) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (vi) the Company failed to properly assess the risks of its equipment; (vii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (viii) the Company's conduct created material risks to Edison's earnings and dividend growth; (ix) the Company conflated issues of electric service reliability and safety; and (xi) as a result, the Company's public statements were materially false and misleading at all relevant times.

<u>Q3 2016 10-Q</u>

300. That same day, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q3 2016 10-Q"). The Q3 2016 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

> *Wildfire Insurance*
>
> Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Prolonged drought conditions in California have also increased the duration of the wildfire season and the risk of severe wildfire events.*** SCE

> has approximately $1 billion of insurance coverage for wildfire liabilities for the period ending on May 31, 2017. SCE has a self-insured retention of $10 million per wildfire occurrence. SCE or its contractors may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage.

301. The risk factors referenced in ¶300 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically, the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or prolonged drought conditions to include risks created by the Company's own reckless disregard of safety, as described in ¶299 above.

302. In the Q3 2016 10-Q, the Company stated that:

> Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this MD&A and in Edison International's and SCE's combined 2015 Form 10-K, including the "Risk Factors" section. ***Readers are urged to read this entire report, including the information incorporated by reference, as well as the 2015 Form 10-K***, and carefully consider the risks, uncertainties and other factors that affect Edison International's and SCE's businesses.

303. As discussed above, in the 2015 10-K, the Company discussed the following risk factors, in addition to wildfire insurance:

a) Failure to remediate aging infrastructure:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates the operational risks and the need for superior execution in its activities***. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation

of which can be hazardous. SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

b) Damage to private and public property:

The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.

Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant***. The CPUC has increased its focus on public safety issues with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

304. The risk factors referenced in ¶303(a) above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶275 above.

305. The risk factors referenced in ¶303(b) above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as in ¶277 above.

306. In the Q3 2016 10-Q, the Company further stated, under the heading

"2018 General Rate Case": "***The capital programs requested in SCE's 2018 GRC are focused on safety and reliability through investments in the distribution grid to replace aging equipment*** and enhance capabilities to integrate increasing amounts of Distributed Energy Resources ('DER')."

307. The statements referenced in ¶306 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, including in connection with its 2018 GRC, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) consequently, the Company was not "focused on safety"; (xii) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xiii) as a result, the Company's public

statements were materially false and misleading at all relevant times.

Q3 2016 Earnings Call

308. That same day – November 1, 2016 – the SCE Defendants held a conference call with investors and analysts (the "Q3 2016 Earnings Call"), during which Defendant Pizarro claimed that SCE's 2018 GRC "demonstrate[d] SCE's commitment to … ***maintain[ing] a safe and reliable wires network*** [and] … ***continu[ing] our operational excellence journey to achieve top quartile performance*** in ***safety***, reliability, customer satisfaction and cost."

309. The statements referenced in ¶308 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, including in connection with its 2018 GRC, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and

regulations; (xi) consequently, the Company was not "focus[ed] on safety"; (xii) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xiii) as a result, the Company's public statements were materially false and misleading at all relevant times.

310. Also during the Q3 2016 Earnings Call, Defendant Pizarro discussed the 2015 Long Beach fires and outages as follows:

> I also want to comment on the CPUC proceeding examining the SCE customer outages in Long Beach in July 2015. You may recall that we had multiple underground vault fires and underground cable failures, which affected much of the downturn area and adjoining neighborhoods. ***The problems centered in a unique portion of SCE's distribution system that is arranged in network configuration, similar to those used in dense urban areas like Manhattan. Most of our system has a radial design instead*. *SCE has made a number of changes in our systems and management processes as a result of these outages.*** The CPUC proceeding will determine if fines are warranted and propose penalty amounts, which could be significant but we are not able to estimate these at this early stage of the proceeding. Hearings are scheduled for February of next year.

311. The statements referenced in ¶310 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) The Long Beach outages affected not only those customers served by Edison's Long Beach secondary network, but at times extended to 30,000 customers, including customers who receive their power from radial circuits that also feed the secondary network, and thus Edison downplayed the scope of its safety violations; (ii) the Company failed to replace or reinforce aging and unsafe electrical infrastructure, resulting in fire incidents; (iii) the Company deployed a

"run-to-failure" maintenance model that consciously allowed for equipment aging and consequent failure; (iv) the Company's noncompliant electricity networks created a significantly heightened fire risk; (v) the Company failed to properly assess the risks of its equipment; (vi) the Company failed to remediate these deficiencies between the time of the Long Beach outages and the Q3 2016 Earnings Call; and (vii) as a result, the Company's public statements were materially false and misleading at all relevant times.

312. Later in the Q3 2016 Earnings Call, Defendant Rigatti stated, in response to an analyst question regarding the Company's equity ratio, "[w]e're trying to balance a lot of things in the context of, ***we want to be able to deploy the capital that we need to get the grid modernized, to focus on safety and reliability***, all the things that our customers need, and then also balance that against customer rates as well. So, we're doing a lot of things."

313. The statements referenced in ¶312 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model

that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, including in connection with its 2018 GRC, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) consequently, the Company was not "focus[ed] on safety"; (xii) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xiii) as a result, the Company's public statements were materially false and misleading at all relevant times.

November 2, 2016 Business Update

314. On November 2, 2016, the Company filed a presentation on Form 8-K with the SEC – entitled "Business Update November 2016" – which included a slide substantially similar to the one reproduced at in ¶296 above, and which falsely characterized SCE's 2018 GRC filing as "consistent with SCE strategy to focus on safety and reliability."

315. The statements contained in ¶314 were materially false and misleading for the reasons discussed in ¶297 above.

2016 10-K

316. On February 21, 2017, the Company filed its annual statement on Form 10-K for the fiscal year ending December 31, 2016 (the "2016 10-K"). The 2016 10-K was signed by Defendants Pizarro, Payne, Rigatti, and Petmecky.

317. In the 2016 10-K, the Company touted its purported dedication to "modernizing the electric grid ***to improve the safety and reliability of the transmission and distribution network*** … ***SCE's ongoing focus to drive operational and service excellence*** should allow it to achieve these objectives while controlling costs and

customer rates."

318. Further, discussing its capital expenditure plans "***[t]o support a safe and reliable transmission and distribution network***, and to modernize the electric grid", the Company stated that it forecasted capital expenditures of up to $19.3 billion for 2017 through 2020.

319. Commenting on these forecasted expenditures, the 2016 10-K states that the "2017 capital expenditures is a baseline of grid modernization spending that will ***promote increased safety and reliability*** and also allow for a timely ramp-up of grid modernization capital expenditures in subsequent years."

320. The statements referenced in ¶¶317-19 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment; (x) the Company was in violation of state law and regulations; (xi)

consequently, the Company did not possess any "ongoing focus to drive operational and service excellence" with respect to safety or any baseline of safety to "increase"; (xii) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xiii) as a result, the Company's public statements were materially false and misleading at all relevant times.

321. The Company also discussed its 2018 GRC, stating that "[t]he capital programs requested in SCE's 2018 GRC ***are focused on safety and reliability through investments in the distribution grid to replace aging equipment*** ….."

322. The statements referenced in ¶321 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, including in

connection with its 2018 GRC, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) consequently, the Company was not "focused on safety"; (xii) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xiii) as a result, the Company's public statements were materially false and misleading at all relevant times.

323. Discussing the ratemaking process overseen by CPUC, the 2016 10-K notes the importance of safety measures put in place by SCE, explaining:

> ***The CPUC is conducting a triennial safety model assessment proceeding ("S-MAP") to evaluate the utility models used to prioritize safety risks, examine the utilities' assessment of their key risks and their proposed mitigation programs, and develop requirements for annual reporting of risk spending and mitigation results.***

324. The statements referenced in ¶323 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that (i) they were already aware, no later than January 31, 2017, that SED was highly critical of Edison's risk assessment practices; (ii) they were already aware, no later than January 31, 2017, of SED's determination that it would be "unwise to accept Edison's risk assessment methods as a basis for determining reasonableness of safety-related program requests"; (iii) they were already aware, no later than January 31, 2017, of SED's determination that Edison classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (iv) as a result, the Company's public statements were

materially false and misleading at all relevant times.

325. The 2016 10-K discussed Edison's purported infrastructure investment program, as well as the risks posed to the Company's financial condition and operations by its failure to remediate aging infrastructure, stating in relevant part:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates operational risks and the need for superior execution in SCE's activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous.*** SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

326. The statements referenced in ¶325 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were

actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, including in connection with its 2018 GRC, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) consequently, the Company was in violation of state law and regulations; (xi) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xii) as a result, the Company's public statements were materially false and misleading at all relevant times.

327. In addition, the risk factors referenced in ¶325 above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, with respect to the July-August 2015 Long Beach outages, which affected to 30,000 customers, caused fires in several underground structures, and resulted in explosions that blew manhole covers into the air. Moreover, the SCE Defendants knew their claimed infrastructure investments were insufficient to mitigate the cited risks for the reasons described in ¶326 above

328. The SCE Defendants acknowledged in 2016 10-K that their business may result in damage to private and public property, as well as injuries to bystanders, stating in relevant part:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***
>
> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through

downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant***. No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage. The CPUC has increased its focus on public safety with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

329. The risk factors referenced in ¶328 above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, the SCE Defendants had already (i) failed to maintain electrical equipment that injured three U.S. Marines in Twentynine Palms in 2015; (ii) caused the Potrero Fire of November 2015, in which the Company was cited for failing to replace or reinforce an unsafe utility pole; (iii) been fined $50,000 for the fatal electrocution at Edison's Whittier facility; and (iv) received numerous citations for safety violations between April 4, 2016 and February 10, 2017. More specifically, the SCE Defendants knew their potential liability extended well beyond "inherent risks" to include risks created by the Company's own reckless disregard of safety, as described in ¶326 above.

330. Relatedly, the 2016 10-K discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

SCE's insurance coverage for wildfires arising from its ordinary operations may not be sufficient.

Edison International has experienced increased costs and difficulties in obtaining insurance coverage for wildfires that could arise from SCE's ordinary operations. Edison International, SCE or its contractors may experience coverage reductions

> and/or increased wildfire insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage. Uninsured losses and increases in the cost of insurance may not be recoverable in customer rates. A loss which is not fully insured or cannot be recovered in customer rates could materially affect Edison International's and SCE's financial condition and results of operation
>
> * * *
>
> *Wildfire Insurance*
>
> Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Drought conditions in California have also increased the duration of the wildfire season and the risk of severe wildfire events***. SCE has approximately $1 billion of insurance coverage for wildfire liabilities for the period ending on May 31, 2017. SCE has a self-insured retention of $10 million per wildfire occurrence. ***SCE or its contractors may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage.***

331. The risk factors referenced in ¶330 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically, the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or prolonged drought conditions to include risks created by the Company's own reckless disregard of safety, as described in ¶326 above.

332. The 2016 10-K discussed a prior incident where its equipment malfunctioned and caused multiple fires in Long Beach, California:

> ***In July 2015, SCE's customers who are served via the network portion of SCE's electric system in Long Beach, California experienced service interruptions due to multiple underground vault fires and underground cable failures.*** No personal injuries were reported in connection with these events. SCE expects to incur penalties as a result of these events. Although resolution will be subject to settlement discussions with SED and CPUC review and approval, SCE has recorded a liability for the estimated loss.

333. The statements referenced in ¶332 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) The Long Beach outages affected not only those customers served by Edison's Long Beach secondary network, but at times extended to 30,000 customers, including customers who receive their power from radial circuits that also feed the secondary network, and thus Edison downplayed the scope of its safety violations; (ii) the Company failed to replace or reinforce aging and unsafe electrical infrastructure, resulting in fire incidents; (iii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment aging and consequent failure; (iv) the Company's noncompliant electricity networks created a significantly heightened fire risk; (v) the Company failed to properly assess the risks of its equipment; and (vi) as a result, the Company's public statements were materially false and misleading at all relevant times.

<u>Q4 2016 Earnings Call</u>

334. On February 21, 2017, the SCE Defendants held a conference call with investors and analysts (the "Q4 2016 Earnings Call"), during which Defendant Pizarro stated, in part:

> I'd like to touch on a few of the key non-financial metrics the board uses in measuring our performance annually. Though they may not be as critical to

> investors, they are critical to how we measure our performance in delivering ***safe***, reliable, clean and affordable electricity to our customers. ***A major priority across our company is being safe*** and though we've improved our performance in our journey to injury free, we have much more to do to meet the performance of our best-in-class peers. ***To that end, we have elevated safety to one of our company's core values and dedicated additional senior leadership in this area***.

335. The statements referenced in ¶334 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, including in connection with its 2018 GRC, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) consequently, the Company was in violation of state law and regulations; (xi) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (xii) as a

result, the Company's public statements were materially false and misleading at all relevant times.

Q1 2017 10-Q

336. On May 1, 2017, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q1 2017 10-Q"). The Q1 2017 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

> *Wildfire Insurance*
>
> Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Drought conditions in California have also increased the duration of the wildfire season and the risk of severe wildfire events.*** SCE has approximately $1 billion of insurance coverage for wildfire liabilities for the period ending on May 31, 2017. SCE has a self-insured retention of $10 million per wildfire occurrence. ***SCE or its contractors may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage.***

337. The risk factors referenced in ¶336 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically, the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or drought conditions to include risks created by the Company's own reckless disregard of safety, as described in ¶335 above.

338. In the Q1 2017 10-Q, the Company stated that:

> Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this report and in the 2016 Form 10-K, including the "Risk Factors" section. Readers are urged to read this entire report, including ***information incorporated by reference, as well as the 2016 Form 10-K***, and carefully consider the risks, uncertainties, and other factors that affect Edison International's and SCE's businesses.

339. As discussed above, in the 2016 10-K, the Company discussed the following risk factors, in addition to wildfire insurance:

a) Failure to remediate aging infrastructure:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates operational risks and the need for superior execution in SCE's activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous.*** SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

b) Damage to private and public property:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***
>
> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant.*** No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage. The CPUC has increased its focus on

> public safety with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

340. The risk factors referenced in ¶339(a) above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶327 above.

341. The risk factors referenced in ¶339(b) above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶329 above.

<u>Q1 2017 Earnings Call</u>

342. That same day – May 1, 2016 – the SCE Defendants held a conference call with investors and analysts (the "Q1 2017 Earnings Call"), during which Defendant Pizarro stated, in part:

> My comments today focus on Southern California Edison's long-term growth opportunity. I'll start with the SCE 2018 General Rate Case. SCE's filing outline a continued focus on infrastructure reliability investment. It also proposed the first elements of a multi-year grid modernization initiative, one that will be a key enabler of California's ambitious climate change policies, ***as well as supporting improved system reliability and public safety***.

343. Also during the Q1 2017 Earnings Call, Defendant Rigatti stated, in response to an analyst inquiry:

> [W]e actually will file – for our 2021 GRC, we will file a similar filing next

> year. It's part of the process as it is unfolding. ***I think, from a safety culture perspective, we actually already look at all of our capital through a safety lens and are determining all the time, with or without the ramp, whether or not we are appropriately addressing all of the safety concerns and the safety needs of the company. So I would say, you'll continue to see us have that focus on infrastructure replacement, which has both the safety aspect to it as well as the reliability aspect to it***.

344. The statements referenced in ¶¶342-43 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, including in connection with its 2018 GRC, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) consequently, the Company was in violation of state law and regulations; (xi) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than

safety; (xii) the Company did not look at all of its capital "through a safety lens" and was not "determining all the time … whether or not [it] [was] appropriately addressing all of the safety concerns and the safety needs of the company"; and (xiii) as a result, the Company's public statements were materially false and misleading at all relevant times.

345. During the Second Quarter of 2017, the Company and the Underwriter Defendants completed the Offering, allowing Edison to raise $475 million on the basis of the false and misleading statements contained in the Offering Documents.

Preferred Shares Offering

346. Pursuant to (i) the registration statement on Form S-3 filed by the Company and the SCE Trust VI (File No. 333-206060) dated and filed with the SEC on June 14, 2017 (the "Registration Statement") and (ii) the prospectus dated June 19, 2017 (the "Prospectus") and filed with the SEC on June 20, 2017, SCE issued $475 million of 5.00% Series L preference stock to SCE Trust VI, a special purpose entity formed to issue trust securities.

347. The Underwriter Defendants purchased the preferred shares from SCE Trust VI, and then offered the Trust Preference Securities to the public at the public offering price of $25 per share.

348. SCE Trust VI's ability to make distributions on the Trust Preference Securities was made contingent on its ability to make dividend payments on the Series L Preference Shares.

349. The Offering Prospectus incorporated by reference the 2016 10-K and Q1 2017 10-Q, which were materially false and misleading for the reasons set forth in ¶¶316-33 & 336-41 above.

350. The Offering Registration Statement incorporated by reference the Offering Prospectus, which was materially false and misleading for the reasons set

forth in ¶349 above.

351. As a result, the Offering Documents referred to in ¶346 above were materially false and misleading at all relevant times.

Q2 2017 10-Q

352. On July 27, 2017, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q2 2017 10-Q"). The Q2 2017 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

> *Wildfire Insurance*
>
> Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Drought conditions in California have also increased the duration of the wildfire season and the risk of severe wildfire events***. SCE has approximately $1 billion of insurance coverage for wildfire liabilities for the period ending on May 31, 2018. SCE has a self-insured retention of $10 million per wildfire occurrence. Various coverage limitations within the policies that make up this insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy period. ***SCE or its vegetation management contractors may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of insurance coverage.***

353. The risk factors referenced in ¶352 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically,

the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or drought conditions to include risks created by the Company's own reckless disregard of safety, as described in ¶344 above.

354. In the Q2 2017 10-Q, the Company stated that:

> Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this report and in the 2016 Form 10-K, including the "Risk Factors" section. ***Readers are urged to read this entire report, including information incorporated by reference, as well as the 2016 Form 10-K***, and carefully consider the risks, uncertainties, and other factors that affect Edison International's and SCE's businesses.

355. As discussed above, in the 2016 10-K, the Company discussed the following risk factors, in addition to wildfire insurance:

a) Failure to remediate aging infrastructure:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates operational risks and the need for superior execution in SCE's activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous.*** SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

b) Damage to private and public property:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***

> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant.*** No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage. The CPUC has increased its focus on public safety with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations***.

356. The risk factors referenced in ¶355(a) above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶327 above.

357. The risk factors referenced in ¶355(b) above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶329 above.

Q2 2017 Earnings Call

358. The same day, July 27, 2017, the SCE Defendants held a conference call with investors and analysts (the "Q2 2017 Earnings Call"), during which Defendant Pizarro claimed that "***[s]afety and reliability are always at the forefront of our capital spending plans and we must now implement those plans in the context of also building a modern grid to integrate distributed energy resources*** that our customers are choosing and that our regulators are supporting."

359. During the same call, Defendant Payne claimed "that grid modernization [ ] has very significant reliability and safety benefits …."

360. The statements referenced in ¶¶358-59 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) consequently, the Company was in violation of state law and regulations; (xi) the Company classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; (xii) the Company had already been told by SED that it should not conflate safety and grid modernization; (xiii) safety was not "always at the forefront" of the Company's capital spending plans and (xiv) as a result, the Company's public statements were materially false and

misleading at all relevant times.

Q3 2017 10-Q

361. On October 30, 2017, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q3 2017 10-Q"). The Q3 2017 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

> *Wildfire Insurance*
>
> Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. ***Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. Drought conditions in California have also increased the duration of the wildfire season and the risk of severe wildfire events.*** SCE has approximately $1 billion of insurance coverage for wildfire liabilities for the period ending on May 31, 2018. SCE has a self-insured retention of $10 million per wildfire occurrence. Various coverage limitations within the policies that make up this insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy period. SCE or its vegetation management contractors may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of insurance coverage.

362. The risk factors referenced in ¶361 above relating to wildfire insurance were false and misleading because at the time the statements were made, the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation and/or prolonged drought conditions in California. More specifically, the SCE Defendants knew their potential liability extended well beyond inverse condemnation and/or drought conditions to include risks created by the Company's

own reckless disregard of safety, as described in ¶360 above.

363. In the Q3 2017 10-Q, the Company stated that:

> Additional information about risks and uncertainties, including more detail about the factors described in this report, is contained throughout this report and in the 2016 Form 10-K, including the "Risk Factors" section. ***Readers are urged to read this entire report, including information incorporated by reference, as well as the 2016 Form 10-K***, and carefully consider the risks, uncertainties, and other factors that affect Edison International's and SCE's businesses.

364. As discussed above, in the 2016 10-K, the Company discussed the following risk factors, in addition to wildfire insurance:

a) Failure to remediate aging infrastructure:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates operational risks and the need for superior execution in SCE's activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous.*** SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

b) Damage to private and public property:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***
>
> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***Injuries and property***

> ***damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant.*** No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage. The CPUC has increased its focus on public safety with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

365. The risk factors referenced in ¶364(a) above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶327 above.

366. The risk factors referenced in ¶364(b) above relating to prospective citations and fines were false and misleading because at the time the allegedly prospective risks were discussed, they had already come to fruition, albeit on a limited basis, as discussed in ¶329 above.

Q3 2017 Earnings Call

367. The same day, October 30, 2017, the SCE Defendants held a conference call with investors and analysts (the "Q3 2017 Earnings Call"), during which Defendant Pizarro stated that:

> Wildfires are all too common in California, and situations like this remind us to stay vigilant in our risk management and to be safe in our day-to-day operations ….
>
> ***We are engaging with regulators on this topic and on the practices and orders that we have implemented to date. These include managing the electric system with a focus on public and worker safety, as well as on reliability of the system***.

> ***In addition to operating practices designed to reduce the risk of wildfires, SCE also invests significant amounts of capital to reduce wildfire risk. Examples include our pole replacement and vegetation management programs. These are all part of our mandate to provide safe, reliable, and ubiquitous electric service,*** even as we and our peer utilities have seen increased siting of new homes and businesses in areas with higher fire risk across the state over the past decades.

368. The statements referenced in ¶367 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California; (ix) the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) consequently, the Company was in violation of state law and regulations; (xi) the Company classified major categories of spending as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; (xii) the Company had already been told by SED that it should not conflate safety and

reliability; and (xiii) as a result, the Company's public statements were materially false and misleading at all relevant times.

2017 10-K

369. On February 22, 2018, the Company filed its annual statement on Form 10-K for the fiscal year ending December 31, 2017 (the "2017 10-K"). The 2017 10-K was signed by Defendants Pizarro, Payne, Rigatti, and Petmecky.

370. In the 2017 10-K, the Company touted its purported dedication to "modernizing the electric grid ***to improve the safety and reliability of the transmission and distribution network … SCE's ongoing focus to drive operational and service excellence*** is intended to allow it to achieve these objectives safely while controlling costs and customer rates."

371. The statements referenced in ¶370 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California,

which had partially materialized with, *inter alia*, the Thomas Fire; (ix) the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) consequently, the Company did not possess any "ongoing focus to drive operational and service excellence" with respect to safety or any baseline of safety to "increase"; (xii) the Company classified major categories of spending as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; (xiii) the Company had already been told by SED that it should not conflate safety and reliability; and (xiv) as a result, the Company's public statements were materially false and misleading at all relevant times.

372. Discussing the ratemaking process overseen by CPUC, the 2017 10-K notes the importance of safety measures put in place by SCE, explaining:

> ***The CPUC is conducting a triennial safety model assessment proceeding ("S-MAP") to evaluate the utility models used to prioritize safety risks, examine the utilities' assessment of their key risks and their proposed mitigation programs, and develop requirements for annual reporting of risk spending and mitigation results.***

373. The statements referenced in ¶372 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that (i) they were already aware, no later than January 31, 2017, that SED was highly critical of Edison's risk assessment practices; (ii) they were already aware, no later than January 31, 2017, of SED's determination that it would be "unwise to accept Edison's risk assessment methods as a basis for determining reasonableness of safety-related program requests"; (iii) they were already

aware, no later than January 31, 2017, of SED's determination that Edison classified major categories of spending – including grid improvement – as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; and (iv) as a result, the Company's public statements were materially false and misleading at all relevant times.

374. The 2017 10-K discussed Edison's purported infrastructure investment program, as well as the risks posed to the Company's financial condition and operations by its failure to remediate aging infrastructure, stating in relevant part:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates operational risks and the need for superior execution in SCE's activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous.*** SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

375. The statements referenced in ¶374 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess,

remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had partially materialized with the Thomas Fire; (ix) the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) consequently, the Company did not elevate operational risks; (xii) the Company classified major categories of spending as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; (xiii) the Company had already been told by SED that it should not conflate safety and reliability; and (xiv) as a result, the Company's public statements were materially false and misleading at all relevant times.

376. In addition, the risk factors referenced in ¶374 above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already: (i) come to fruition, albeit on a limited basis, with the July-August 2015 Long Beach outages, which affected to 30,000 customers, caused fires in several underground structures, and resulted in explosions that blew manhole covers into the air; and (ii) partially materialized via the Thomas Fire and subsequent mudslides. Moreover, the SCE Defendants knew their claimed infrastructure investments were insufficient to mitigate the cited risks for the reasons described in ¶375 above.

377. The SCE Defendants acknowledged in 2017 10-K that their business may

result in damage to private and public property, as well as injuries to bystanders, stating in relevant part:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***
>
> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant***. No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage. The CPUC has increased its focus on public safety with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $50,000 per violation per day, pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

378. The risk factors referenced in ¶377 above relating to prospective citations and fines were false and misleading come to fruition, albeit on a limited basis, with respect to: (i) failing to maintain electrical equipment that injured three U.S. Marines in Twentynine Palms in 2015; (ii) the Potrero Fire of November 2015, in which the Company was cited for failing to replace or reinforce an unsafe utility pole; (iii) the fatal electrocution at Edison's Whittier facility, for which Edison was fined $50,000 on February 12, 2016; (iv) Edison's numerous citations for safety violations between April 4, 2016 and February 9, 2018; and (v) the Liberty Fire. In addition, (vi) the risks had already partially materialized via the Thomas Fire and subsequent mudslides, and the SCE Defendants were directly aware, no later than December 27, 2017, due to meetings between investigators and SCE representatives, that Edison had started the Thomas Fire.

At all relevant times, the SCE Defendants knew their potential liability extended well beyond "inherent risks" to include risks created by the Company's own reckless disregard of safety, as described in ¶375 above.

379. The 2017 10-K also discussed various risks to the Company as a result of wildfire related liabilities, including its possible inability to pay distributions to investors who purchased in the Offering:

> ***Damage claims against SCE for wildfire-related losses may materially affect SCE's financial condition and results of operations.***
>
> ***Prolonged drought conditions and shifting weather patterns in California resulting from climate change as well as increased tree mortality rates have increased the duration of the wildfire season and the risk of severe wildfire events. Severe wildfires and increased urban development in high fire risk areas in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of utility practices and/or the failure of electric and other utility equipment. Certain California courts have previously found utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. The rationale stated by these courts for applying this theory to investor-owned utilities is that property losses resulting from a public improvement, such as the distribution of electricity, can be spread across the larger community that benefited from such improvement.*** However, in December 2017, the CPUC issued a decision denying the investor-owned utility's request to include in its rates uninsured wildfire-related costs arising from several 2007 fires, finding that the investor-owned utility did not prudently manage and operate its facilities prior to or at the outset of the 2007 wildfires. An inability to recover uninsured wildfire-related costs could materially affect SCE's business, financial condition and results of operations. For example, ***if SCE is found liable for damages related to the December 2017 Wildfires, and SCE is unable to, or believes that it will be unable to, recover those damages, SCE may not have sufficient cash or equity to pay dividends to Edison International or may be prohibited from declaring such dividends because it does not meet California law***

requirements for the declaration of dividends . . . .

380. The 2017 10-K further discussed wildfires in southern California in December of 2017, and noted the serious risks that may arise should the Company be found responsible for the fires. Specifically, the filing stated in relevant part:

> **Southern California Wildfires**
>
> In December 2017, several wind-driven wildfires (the "December 2017 Wildfires") impacted portions of SCE's service territory and caused substantial damage to both residential and business properties and service outages for SCE customers.
>
> The largest of these fires, known as the Thomas Fire, originated in Ventura County and burned acreage located in both Ventura and Santa Barbara Counties. According to the most recent California Department of Forestry and Fire Protection ("Cal Fire") incident information reports, the Thomas Fire burned over 280,000 acres, destroyed an estimated 1,063 structures, damaged an estimated 280 structures and resulted in two fatalities. During 2017, SCE incurred approximately $35 million of capital expenditures related to restoration of service resulting from the December 2017 Wildfires.
>
> The causes of the December 2017 Wildfires are being investigated by Cal Fire and other fire agencies. ***SCE believes the investigations include the possible role of SCE's facilities***. SCE expects that one or more of the fire agencies will ultimately issue reports concerning the origins and causes of the December 2017 Wildfires but cannot predict when these reports will be released or if any findings will be issued before the investigations are completed.
>
> ***Any potential liability of SCE for December 2017 Wildfire-related damages will depend on a number of factors, including whether SCE is determined to have substantially caused, or contributed to, the damages and whether parties seeking recovery of damages will be required to show negligence in addition to causation.*** Certain California courts have previously found utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire

that caused the property damage. The rationale stated by these courts for applying this theory to investor-owned utilities is that property losses resulting from a public improvement, such as the distribution of electricity, can be spread across the larger community that benefited from such improvement. ***However, in December 2017, the CPUC issued a decision denying the investor-owned utility's request to include in its rates uninsured wildfire-related costs arising from several 2007 fires, finding that the investor-owned utility did not prudently manage and operate its facilities prior to or at the outset of the 2007 wildfires.***

….

Given the preliminary stages of the investigations and the uncertainty as to the causes of the December 2017 Wildfires, and the extent and magnitude of potential damages, Edison International and SCE are currently unable to reasonably estimate whether SCE will incur material losses and, if so, the range of possible losses that could be incurred.

…. ***Should responsibility for damages be attributed to*** SCE for a significant portion of the losses related to the December 2017 Wildfires, SCE's insurance may not be sufficient to cover all such damages. SCE or its vegetation management contractors may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of insurance coverage.

In addition, SCE may not be authorized to recover its uninsured damages through customer rates if, for example, the CPUC finds that the damages were incurred because SCE was not a prudent manager of its facilities. ***The CPUC's Safety and Enforcement Division ("SED") is conducting an investigation to assess the compliance of SCE's facilities with applicable rules and regulations in areas impacted by the December 2017 Wildfires***.

381. Similarly, the 2017 10-K discussed another natural disaster which occurred in Santa Barbara County, California in January of 2018:

Montecito Mudslides

In January 2018, torrential rains in Santa Barbara County produced mudslides and flooding in Montecito and surrounding areas (the "Montecito

Mudslides"). According to Santa Barbara County, the Montecito Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures, and resulted in at least 21 fatalities, with two additional fatalities presumed.

Six of the lawsuits mentioned above allege that SCE has responsibility for the Thomas Fire and that the Thomas Fire proximately caused the Montecito Mudslides, resulting in the plaintiffs' claimed damages. SCE expects that additional lawsuits related to the Montecito Mudslides will be filed.

As noted above, the cause of the Thomas Fire has not been determined. In the event that SCE is determined to have liability for damages caused by the Thomas Fire, SCE cannot predict whether the courts will conclude that the Montecito Mudslides were caused by the Thomas Fire or that SCE is responsible or liable for damages caused by the Montecito Mudslides. As a result, Edison International and SCE are currently unable to reasonably estimate whether SCE will incur material losses and, if so, the range of possible losses that could be incurred. If it is determined that the Montecito Mudslides were caused by the Thomas Fire and that SCE is responsible or liable for damages caused by the Montecito Mudslides, then SCE's insurance coverage for such losses may be limited to its wildfire insurance. Additionally, if SCE is determined to be liable for a significant portion of costs associated with the Montecito Mudslides, SCE's insurance may not be sufficient to cover all such damages and SCE may be unable to recover any uninsured losses.

If it is ultimately determined that SCE is legally responsible for losses caused by the Montecito Mudslides, SCE could be held liable for resulting Property Losses if inverse condemnation is found applicable. If SCE is determined to have been negligent, in addition to Property Losses, SCE could be liable for business interruption losses, evacuation costs, clean-up costs, medical expenses and personal injury/wrongful death claims associated with the Montecito Mudslides. These liabilities, in the aggregate, could be substantial. ***SCE cannot predict whether it will be subjected to regulatory fines related to the Montecito Mudslides***.

382. The statements referenced in ¶¶379-81 above were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business,

operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings between investigators and SCE representatives; (ii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iii) Edison's liability for the Thomas Fire and/or Montecito Mudslides was not merely speculative, but highly likely given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly

heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas Fire; and

- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations;

(iv) consequently, Edison had not prudently managed and operated its facilities prior to the Thomas Fire, and therefore understood the extent of its potential liability; and (v) as a result, the Company's public statements were materially false and misleading at all relevant times.

383. In addition, the risk factors referenced in ¶¶379-81 above relating to prospective citations and fines were false and misleading because at the time the statements were made, the risk had already materialized with respect to (i) Edison's direct awareness, no later than December 27, 2017, due to meetings between investigators and SCE representatives, that it had started the Thomas Fire; and (ii) Edison's related awareness that it had caused the Montecito Mudslides, which resulted in twenty-two deaths, including child deaths.

Q4 2017 Earnings Call

384. That same day – February 22, 2018 – the SCE Defendants held a conference call with investors and analysts (the "Q4 2017 Earnings Call"). During the Q4 2017 Earnings Call, Defendant Pizarro discussed the recent wildfires. Incredibly, less than two months after Edison started the Thomas Fire, Defendant Pizarro (i) radically downplayed utility responsibility for the recent fires; (ii) pointed to a variety of alternate, non-utility-related explanations; and (iii) suggested that the "solution," at least in part, involved reducing the utilities' liability for wildfires:

> ***Wildfires pose a risk statewide, impacting the entire economy. Communities across California have been tragically affected as climate change has increased the severity and the frequency of wildfires in recent***

years. Long-term drought in California and forest management policies have resulted in the build-up of unmanaged vegetation. The state has nearly 130 million dead trees on approximately 9 million acres due to prolonged drought conditions and bark beetle infestation. The combination of these conditions, along with decades of more buildings being permitted and constructed in higher fire risk areas, have contributed to catastrophic wildfires, with eight of the state's 20 most destructive wildfires having occurred in just the last three years.

This is a statewide crisis that needs a statewide solution. We are engaged with state leaders including the Governor's office, legislative leaders and stakeholders across the economy on the solutions we believe are needed. ***First and foremost is the prevention and mitigation of catastrophic wildfires with sufficient fire suppression resources, and effective policies around vegetation management, hazardous fuels reduction, and zoning regulations for residential and commercial development in high fire risk areas***.

Second, our state's infrastructure must be hardened, with stronger building codes in high fire risk areas. Utilities and other operators of critical infrastructure must also partner with state agencies on improved standards for climate resilient infrastructure. As we think about how we design and operate our system, we should consider that roughly a quarter of our service territory is in designated high-fire risk areas. ***We should evaluate the safety impacts, along with the reliability and cost trade-offs***, of steps like undergrounding more of the distribution network in selected areas, installing steel or composite poles instead of wood ones in specific locations, ***and using further preventive public safety shutoffs of power under high-risk conditions such as red flag warnings, which we have done selectively in the past***.

Third, when a catastrophic event occurs in spite of all these efforts, we need thoughtful policies around how financial risks are allocated, including fire suppression costs and damages. As a reminder, California's courts have held investor-owned utilities strictly liable, regardless of fault, for property damages and attorney's fees if utility equipment is found to be a substantial cause of a wildfire. This means that the utility can do everything right in the operation and maintenance of its equipment, but still be on the hook for these costs. The California courts have held utilities

liable regardless of fault by applying the principle of inverse condemnation, a principle typically applicable to government, not to private entities.

385. The statements referenced in ¶384 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the wildfire-related risks described by the Company were not limited to those arising from inverse condemnation, climate change, bark beetle infestations, dead trees, home construction in high fire areas, and/or prolonged drought conditions in California; (ii) more specifically, the SCE Defendants knew their potential liability included substantial risks created by the Company's own reckless disregard of safety, *e.g.,*:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;

- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas Fire; and
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;

(iii), as a result of the above-described practices, the Company was in violation of state law and regulations; (iv) consequently, the Company was not "engaged" in the "prevention and mitigation of catastrophic wildfires"; (v) the Company had already been told by SED that it should not conflate safety and reliability; and (vi) as a result, the Company's public statements were materially false and misleading at all relevant times.

386. During the same call, Defendant Rigatti stated as follows, in part:

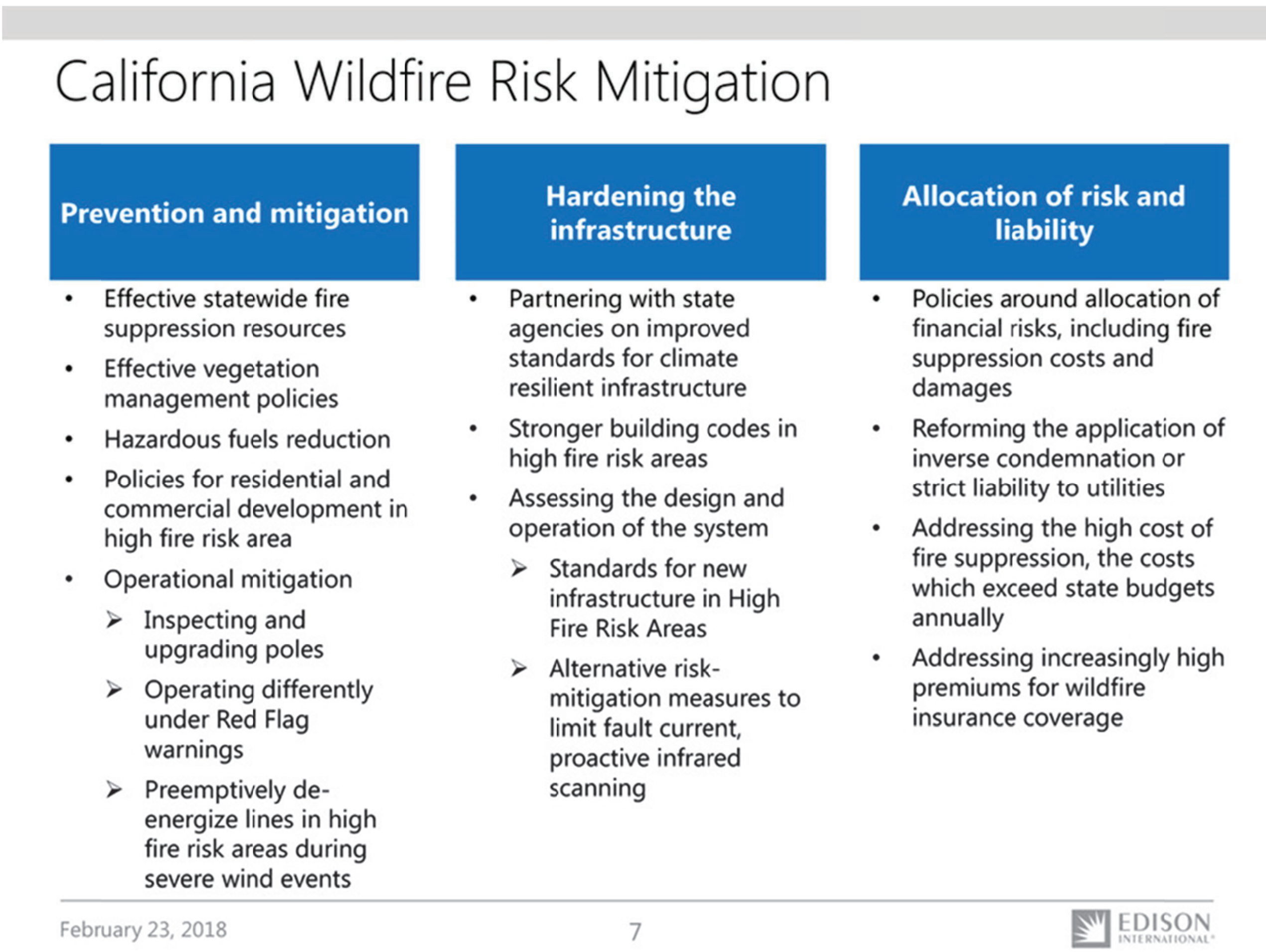
> For the year ended 2017, we have not recorded a liability associated with the December wildfires. ***Given the preliminary stages of the investigations and the uncertainty as to the causes and potential damages associated with the fires, we cannot determine that a liability is probable or a reasonable range of possible losses that could be incurred***. We will continue to update you as we have more information.

387. The statements referenced in ¶386 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings

between investigators and SCE representatives; (ii) Edison's liability for the Thomas Fire was not merely speculative, but probable; and (iii) as a result, the Company's public statements were materially false and misleading at all relevant times.

February 23, 2018 Business Update

388. On February 23, 2018, the Company filed a presentation on Form 8-K with the SEC – entitled "Business Update February 2018" – which included the following slide purporting to depict Edison's current approach to wildfire risk mitigation:



389. The statements referenced in ¶388 were materially false and misleading

because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, (i) the Company failed to mitigate interference with equipment by vegetation, and had been cited for such by CPUC's Electric Safety and Reliability Branch as recently as late May 2018; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (iv) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (v) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vi) the Company failed to use a "[d]ifferent operating protocol under Red Flag warnings" in the run-up to the Thomas Fire, which was preceded by a Red Flag Warning; (vii) the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company; and (viii) as a result, the Company's public statements were materially false and misleading at all relevant times.

Q1 2018 10-Q

390. On May 1, 2018, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q1 2018 10-Q"). The Q1 2018 10-Q discussed the risks posed to the Company's financial condition and operations should it be held responsible for the Thomas Fire, stating in relevant part:

> **Southern California Wildfires**
>
> SCE is aware of multiple lawsuits filed related to the Thomas Fire naming SCE as a defendant. Several of the lawsuits also name Edison International as a defendant. Certain California courts have previously found utilities to be strictly liable for property damage, regardless of fault, by applying the

theory of inverse condemnation when a utilities' facilities were determined to be a substantial cause of a wildfire that caused property damage. ***Any potential liability for December 2017 Wildfire-related damages will depend on a number of factors, including whether SCE substantially caused, or contributed to, the damages and whether parties seeking recovery of damages will be required to show negligence in addition to causation***.

Given the preliminary stages of the investigations and the uncertainty as to the causes of the Thomas Fire, and the extent and magnitude of potential damages, Edison International and SCE are currently unable to predict the outcome of the claims made against SCE and Edison International or reasonably estimate a range of losses that may be incurred. SCE and Edison International's potential liability related to the Thomas Fire could be substantial. ***Additionally, SCE could potentially be subject to fines for alleged violations of CPUC rules and laws in connection with the December 2017 Wildfires***.

…

Montecito Mudslides

In January 2018, torrential rains in Santa Barbara County produced mudslides and flooding in Montecito and surrounding areas (the "Montecito Mudslides"). According to Santa Barbara County initial reports, the Montecito Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures and resulted in at least 21 fatalities, with two additional fatalities presumed.

Of the lawsuits mentioned above, several allege that SCE has responsibility for the Thomas Fire and that the Thomas Fire proximately caused the Montecito Mudslides, resulting in the plaintiffs' claimed damages. Some of the Montecito Mudslides lawsuits also name Edison International as a defendant. Edison International and SCE are currently unable to predict the outcome of the claims made against SCE and Edison International or reasonably estimate a range of losses that may be incurred. SCE and Edison International's potential liability related to the Montecito Mudslides could be substantial, SCE's insurance may not be sufficient to cover such damages, and SCE may not be authorized to recover any uninsured damages in rates.

391. The statements referenced in ¶390 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings between investigators and SCE representatives; (ii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iii) Edison's liability for the Thomas Fire and/or Montecito Mudslides was not merely speculative, but highly likely given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly

vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;

- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas Fire;
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations; and

(iv) as a result, the Company's public statements were materially false and misleading at all relevant times.

392. In addition, the risk factors referenced in ¶390 above relating to prospective citations and fines were false and misleading because at the time the statements were made, the risk had already materialized with respect to (i) Edison's direct awareness, no later than December 27, 2017, due to meetings between investigators and SCE representatives, that it had started the Thomas Fire; and (ii) Edison's related awareness that it had caused the Montecito Mudslides, which resulted in twenty-two deaths, including child deaths.

393. The Q1 2017 10-Q further incorporated by reference the "Risk Factors" set forth in the 2017 10-K, including risks related to Edison's potential failure to remediate aging infrastructure, as set forth in ¶374 above.

394. The risk factors referenced in ¶393 above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already: (i) come to fruition, albeit on a limited basis, with the July-August 2015 Long Beach outages – which affected to 30,000 customers, caused fires in several underground structures, and resulted in explosions that blew manhole covers into the air – and the Liberty Fire; and (ii) partially materialized via the Thomas

Fire and subsequent mudslides. Moreover, the SCE Defendants knew their claimed infrastructure investments were insufficient to mitigate the cited risks for the reasons described in ¶375 above.

Q1 2018 Earnings Call

395. That same day – May 1, 2018 – the SCE Defendants held a conference call with investors and analysts (the "Q1 2018 Earnings Call"). During the Q1 2018 Earnings Call, Defendant Pizarro continued to attribute the recent wildfires to non-utility-based causes, including climate change and construction in high fire areas, and to advocate for reduced the utilities' reduced wildfire liability.

396. In particular, Defendant Pizarro proposed "[a]n updated standard of liability that considers degree of fault, rather than the current standard of strict liability, would ensure that there is a fair sharing of the increasing risk of climate change impacts across society." He stated that Edison planned to challenge inverse condemnation in "appropriate cases, ***including the Thomas Fire lawsuits***."

397. Defendant Pizarro also stated, in part:

> With respect to the Southern California wildfires, a number of external agencies, including Cal Fire, the Ventura County Fire Department, and the CPUC's Safety and Enforcement Division are investigating ***the potential origins and causes of the Thomas Fire***. As we do, in all wildfire matters, SCE is also conducting its own investigation. The investigations continue and we currently cannot predict when they will be completed.

398. The statements referenced in ¶¶395-97 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had actually caused the Thomas Fire, a fact known to the SCE Defendants no later than December

27, 2017, due to meetings between investigators and SCE representatives; (ii) even under the fault-based system of liability, Edison would be held liable for the Thomas Fire, given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas Fire;
- the Company failed to properly assess the risks of its equipment, and therefore

had no strategy in place to remedy the above-discussed deficiencies; and (iii) as a

result, the Company's public statements were materially false and misleading at all relevant times.

July 26, 2018 Press Release

399. On July 26, 2018, the Company issued a press release filed on Form 8-K with the SEC entitled "Edison International Reports Second Quarter 2018 Results," in which Defendant Pizarro claimed, in part: "***[w]e continue our efforts along multiple paths to resolve wildfire-related issues***[.]"

400. The statements referenced in ¶399 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had partially materialized with the Thomas Fire; (ix) the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) consequently, the Company had no substantive program in

place to even begin to "resolve wildfire-related issues"; and (xii) as a result, the Company's public statements were materially false and misleading at all relevant times.

Q2 2018 10-Q

401. On July 26, 2018, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q2 2018 10-Q"). The Q2 2018 10-Q discussed the risks posed to the Company's financial condition and operations should it be held responsible for the Thomas Fire, stating in relevant part:

> **Southern California Wildfires**
>
> SCE is aware of multiple lawsuits filed related to the Thomas Fire naming SCE as a defendant. A number of the lawsuits also name Edison International as a defendant. Certain California courts have previously found utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. ***The extent of potential liability for December 2017 Wildfire-related damages depends on a number of factors, including whether SCE substantially caused, or contributed to, the damages and whether parties seeking recovery of damages will be required to show negligence in addition to causation***.
>
> ***Given the ongoing uncertainty as to the causes of the Thomas Fire***, the complexity of several potential ignition points, and the potential for separate damages to be attributable to fires ignited at separate ignition points, ***Edison International and SCE are currently unable to reasonably estimate a range of losses that may be incurred, but such losses may be material***. ….
>
> Should responsibility for a significant portion of the damages related to the December 2017 Wildfires be attributed to SCE, SCE's insurance may not be sufficient to cover all such damages. In addition, ***SCE may not be authorized to recover its uninsured damages through electric service rates if, for example, the CPUC finds that the damages were incurred because SCE did not prudently manage its facilities***.

…

Montecito Mudslides

In January 2018, torrential rains in Santa Barbara County produced mudslides and flooding in Montecito and surrounding areas. According to Santa Barbara County initial reports, the Montecito Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures and resulted in at least 21 fatalities, with two additional fatalities presumed.

Of the lawsuits mentioned above, several allege that SCE has responsibility for the Thomas Fire and that the Thomas Fire proximately caused the Montecito Mudslides, resulting in the plaintiffs' claimed damages. Some of the Montecito Mudslides lawsuits also name Edison International as a defendant. Edison International and SCE are currently unable to predict the outcome of the claims made against SCE and Edison International or reasonably estimate a range of losses that may be incurred. SCE and Edison International's potential liability related to the Montecito Mudslides could be material, SCE's insurance may not be sufficient to cover such damages, and SCE may not be authorized to recover any uninsured damages in rates.

402. The statements referenced in ¶401 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings between investigators and SCE representatives; (ii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iii) Edison's liability for the Thomas Fire and/or Montecito Mudslides was not merely speculative, but highly likely given that:

- the Company completed numerous work orders past their scheduled date of corrective action;

- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas Fire;
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations; and

(iv) consequently, Edison had not prudently managed and operated its facilities prior to the Thomas Fire, and therefore understood the extent of its potential liability; and (v) as a result, the Company's public statements were materially false and misleading at all relevant times.

403. In addition, the risk factors referenced in ¶401 above relating to prospective citations and fines were false and misleading because at the time the statements were made, the risk had already materialized with respect to (i) Edison's direct awareness, no later than December 27, 2017, due to meetings between investigators and SCE representatives, that it had started the Thomas Fire; and (ii) Edison's related awareness that it had caused the Montecito Mudslides, which resulted in twenty-two deaths, including child deaths.

404. The Q2 2018 10-Q further incorporated by reference the "Risk Factors" set forth in the 2017 10-K, including risks related to Edison's potential failure to remediate aging infrastructure, as set forth in ¶374 above.

405. The risk factors referenced in ¶404 above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already: (i) come to fruition, albeit on a limited basis, with the July-August 2015 Long Beach outages – which affected to 30,000 customers, caused fires in several underground structures, and resulted in explosions that blew manhole covers into the air – and the Liberty Fire; and (ii) partially materialized via the Thomas Fire and subsequent mudslides. Moreover, the SCE Defendants knew their claimed infrastructure investments were insufficient to mitigate the cited risks for the reasons described in ¶375 above.

Q2 2018 Earnings Call

406. The same day, July 26, 2018, the SCE Defendants held a conference call with investors and analysts (the "Q2 2018 Earnings Call"). During the Q2 2018 Earnings Call, Defendant Pizarro stated, in part: "A number of external agencies have been investigating the ***potential origins and causes of the Thomas Fire*** …. As we do in all wildfire matters, SCE is also conducting its own review. The investigations continue and we currently cannot predict when they will be completed."

407. The statements referenced in ¶406 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire through the failure of its equipment, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings between investigators and SCE representatives; and (ii) as a result, the Company's public statements were materially false and misleading at all relevant times.

408. Also during the Q2 2018 Earnings Call, Defendant Pizarro stated, in part:

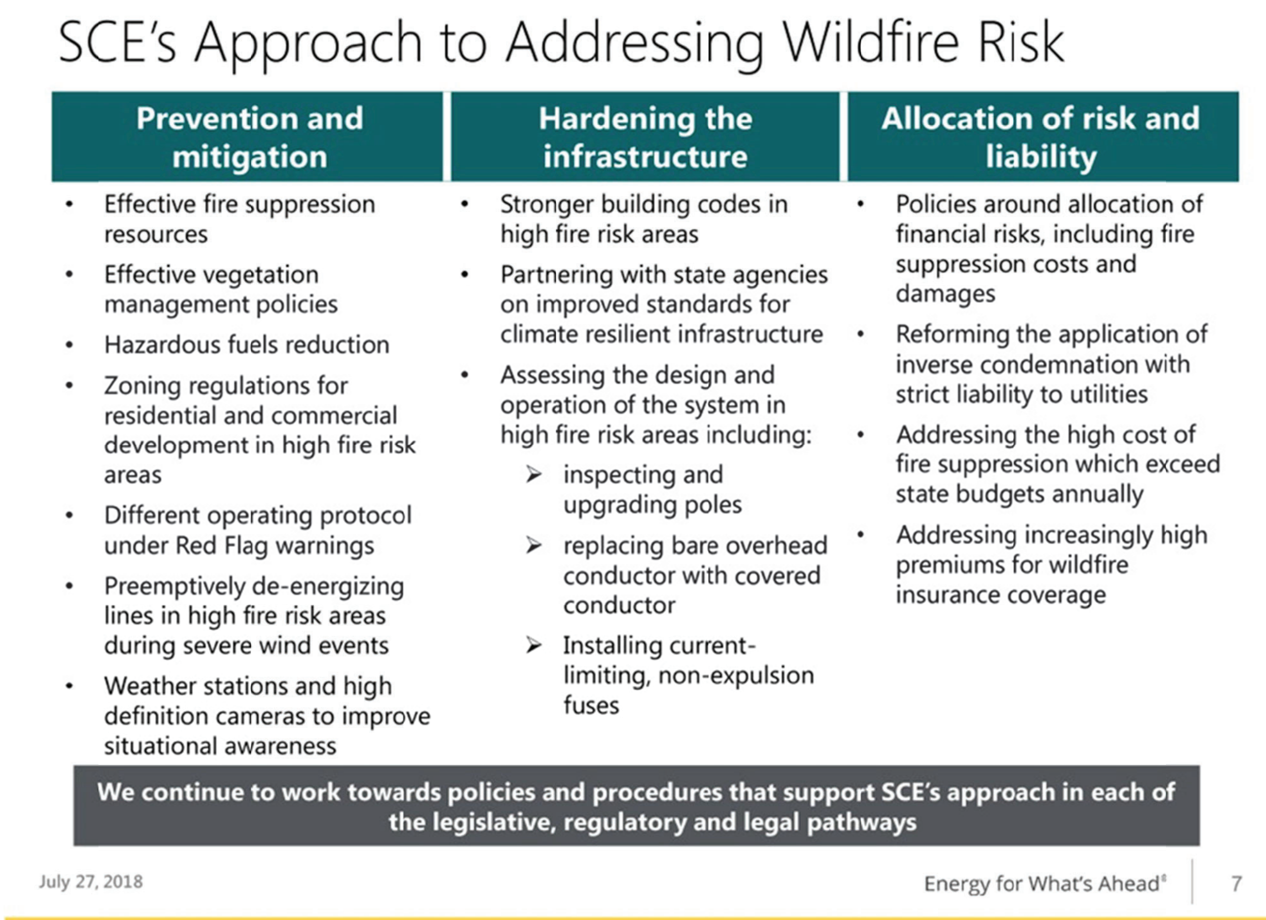
> ***Southern California Edison has spent extensive time reviewing and strengthening our wildfire mitigation and prevention efforts in preparation for the new normal***. Our focus has been on five major areas. ***First, vegetation management. We have increased the vegetation patrols in the most severe high-risk areas and we are evaluating opportunities to perform more expansive tree trimming and tree removal.*** As a reminder, high fire risk areas identified in the CPUC's fire risk maps account for approximately a quarter of our service territory.
>
> Second, hardening our system. We are increasing the use of fire-resistant poles, insulated conductor and non-expulsion fuses in select high fire risk areas. Third, operational practices. ***During Red Flag Warning conditions, we continue to restrict certain types of work and our standard procedure is to not automatically reenergize circuits in high fire risk areas after interruptions until lines are physically inspected. Also, we have refined our protocols for the de-energization of lines when critically necessary to prevent fires and protect public safety, and continue to discuss these with potentially impacted communities***.
>
> Fourth, partnerships. Wildfire response planning occurs with fire agencies, local emergency operation centers and community groups throughout the service territory.
>
> Finally, we maintain a 24-hour situational awareness center and around-the-

clock incident management teams when conditions merit. In certain areas, we are also installing additional weather stations to improve our awareness of local conditions and high-definition cameras to provide early warning of fires both internally and to local fire agencies.

409. The statements referenced in ¶408 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, (i) the Company failed to mitigate interference with equipment by vegetation, and had been cited for such by CPUC's Electric Safety and Reliability Branch as recently as late May 2018; (ii) the Company failed to use a "[d]ifferent operating protocol under Red Flag warnings" in the run-up to the Thomas Fire, which was preceded by a Red Flag Warning; (iii) the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company; and (iv) as a result, the Company's public statements were materially false and misleading at all relevant times.

July 27, 2018 Business Update

410. On July 27, 2018, the Company filed a presentation on Form 8-K with the SEC – entitled "Business Update July 2018" – which included the following slide:



411. The statements referenced in ¶410 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, (i) the Company failed to mitigate interference with equipment by vegetation, and had been cited for such by CPUC's Electric Safety and Reliability Branch as recently as late May 2018; (ii) the Company failed to use a "[d]ifferent operating protocol under Red Flag warnings" in the run-up to the Thomas Fire, which was preceded by a Red Flag Warning; (iii) the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to

de-energize could result in catastrophic financial consequences for the Company; and (iv) as a result, the Company's public statements were materially false and misleading at all relevant times.

Q3 2018 10-Q

412. On October 30, 2018, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q3 2018 10-Q"). The Q3 2018 10-Q discussed the risks posed to the Company's financial condition and operations should it be held responsible for the Thomas Fire, stating in relevant part:

> **Southern California Wildfires**
>
> SCE is aware of multiple lawsuits filed related to the Thomas Fire naming SCE as a defendant. A number of the lawsuits also name Edison International as a defendant. Certain California courts have previously found utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. ***The extent of potential liability for December 2017 Wildfire-related damages depends on a number of factors, including whether SCE substantially caused, or contributed to, the damages and whether parties seeking recovery of damages will be required to show negligence in addition to causation***.
>
> ***Given the ongoing uncertainty as to the causes of the Thomas Fire,*** the complexity of several potential ignition points, and the potential for separate damages to be attributable to fires ignited at separate ignition points, ***Edison International and SCE are currently unable to reasonably estimate a range of losses that may be incurred, but such losses may be material***.….
>
> Should responsibility for a significant portion of the damages related to the December 2017 Wildfires be attributed to SCE, SCE's insurance may not be sufficient to cover all such damages. In addition, ***SCE may not be authorized to recover its uninsured damages through electric service rates if, for example, the CPUC finds that the damages were incurred because SCE did not prudently manage its facilities***…

Montecito Mudslides

In January 2018, torrential rains in Santa Barbara County produced mudslides and flooding in Montecito and surrounding areas. According to Santa Barbara County initial reports, the Montecito Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures and resulted in at least 21 fatalities, with two additional fatalities presumed.

Of the lawsuits mentioned above, several allege that SCE has responsibility for the Thomas Fire and that the Thomas Fire proximately caused the Montecito Mudslides, resulting in the plaintiffs' claimed damages. Some of the Montecito Mudslides lawsuits also name Edison International as a defendant. Edison International and SCE are currently unable to predict the outcome of the claims made against SCE and Edison International or reasonably estimate a range of losses that may be incurred. SCE and Edison International's potential liability related to the Montecito Mudslides could be material, SCE's insurance may not be sufficient to cover such damages, and SCE may not be authorized to recover any uninsured damages in rates.

413. The statements referenced in ¶412 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings between investigators and SCE representatives; (ii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iii) Edison's liability for the Thomas Fire and/or Montecito Mudslides was not merely speculative, but highly likely given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached

wires;

- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas Fire;
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations; and

(iv) consequently, Edison had not prudently managed and operated its facilities prior to the Thomas Fire, and therefore understood the extent of its potential liability; and (v) as a result, the Company's public statements were materially false and misleading at all relevant times.

414. In addition, the risk factors referenced in ¶412 above relating to

prospective citations and fines were false and misleading because at the time the statements were made, the risk had already materialized with respect to (i) Edison's direct awareness, no later than December 27, 2017, due to meetings between investigators and SCE representatives, that it had started the Thomas Fire; and (ii) Edison's related awareness that it had caused the Montecito Mudslides, which resulted in twenty-two deaths, including child deaths.

415. The Q3 2018 10-Q further incorporated by reference the "Risk Factors" set forth in the 2017 10-K, including risks related to Edison's potential failure to remediate aging infrastructure set forth in ¶374 above.

416. The risk factors referenced in ¶415 above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already: (i) come to fruition, albeit on a limited basis, with the July-August 2015 Long Beach outages – which affected to 30,000 customers, caused fires in several underground structures, and resulted in explosions that blew manhole covers into the air – and the Liberty Fire; and (ii) partially materialized via the Thomas Fire and subsequent mudslides. Moreover, the SCE Defendants knew their claimed infrastructure investments were insufficient to mitigate the cited risks for the reasons described in ¶375 above.

<u>Q3 2018 Earnings Call</u>

417. The same day, October 30, 2018, the SCE Defendants held a conference call with investors and analysts (the "Q3 2018 Earnings Call"). During the Q3 2018 Earnings Call, Defendant Pizarro disclosed that Edison's electrical equipment was "associated with" at least one of the two points of origin of the Thomas Fire, and that the Company expected "to incur material losses in connection with the Thomas Fire":

> Based on the progress of our ongoing work in these areas with the information currently available to us, we believe that the Thomas Fire which developed in Ventura County in early December 2017 had at least

two separate ignition points. ***With respect to one of these ignition points, Koenigstein Road, SCE believes that its equipment was associated with this ignition***.

SCE is continuing to assess the progression of the fire from the Koenigstein Road ignition point and the extent of property and other damage that may be attributable to that ignition. At this time, SCE has not determined whether the separate ignition in the Anlauf Canyon area involved our equipment. In the case of both general areas, CAL FIRE has removed SCE equipment. We have not been granted access, which has delayed the completion of our own review.

Given the uncertainty as to the contributing causes of the Thomas Fire, the complexities associated with multiple ignition points and the potential for separate damages to be attributable to fires ignited at separate ignition points, we are currently unable to reasonably estimate a range of losses that may be incurred.

However, we do expect to incur material losses in connection with the Thomas Fire. Given the importance of communicating not just with investors, but also with our communities and other stakeholders, we have echoed some of these disclosures in a separate press release issued simultaneously with today's earnings release.

418. The statements referenced in ¶417 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire through the failure of its equipment, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings between investigators and SCE representatives; (ii) consequently, Edison had been able to reasonably estimate a range of losses that it may have occurred since December 27, 2017; (iii) Edison's equipment was not merely "associated" with the ignition of the Thomas Fire, but actually caused it; (iv) Edison had caused the Thomas Fire at both ignition points; and (v) as a result, the Company's

public statements were materially false and misleading at all relevant times.

419. On October 31, 2018, an analyst report by SunTrust Robinson Humphrey stated that "the next key milestone for us is CalFire's report on the fire and their determination whether the utility violated any state codes." At the time, Edison was well-aware of its persistent violation of state codes leading up to and including the Thomas Fire, yet the market remained in the dark on this critical point.

2018 10-K

420. On February 28, 2019, the Company filed its annual statement on Form 10-K for the fiscal year ending December 31, 2018 (the "2018 10-K"). The 2018 10-K was signed by Defendants Pizarro, Payne, Rigatti, and Petmecky.

421. Discussing the ratemaking process overseen by CPUC, the 2018 10-K notes the importance of safety measures put in place by SCE, explaining:

> ***The CPUC is conducting a triennial safety model assessment proceeding ("S-MAP") to evaluate the utility models used to prioritize safety risks, examine the utilities' assessment of their key risks and their proposed mitigation programs, and develop requirements for annual reporting of risk spending and mitigation results.***

422. The statements referenced in ¶421 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that (i) they were already aware that SED was highly critical of Edison's risk assessment practices; (ii) they were already aware of SED's determination that it would be "unwise to accept Edison's risk assessment methods as a basis for determining reasonableness of safety-related program requests"; (iii) they were already aware of SED's determination that Edison classified major categories of spending – including grid improvement – as safety related, even though

they related to issues of customer satisfaction or electric service reliability, rather than safety; and (iv) as a result, the Company's public statements were materially false and misleading at all relevant times.

423. The 2018 10-K discussed Edison's purported infrastructure investment program, as well as the risks posed to the Company's financial condition and operations by its failure to remediate aging infrastructure, stating in relevant part:

> ***SCE's infrastructure is aging and could pose a risk to system reliability. In order to mitigate this risk, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program elevates operational risks and the need for superior execution in SCE's activities. SCE's financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in operating and maintaining its facilities, the operation of which can be hazardous.*** SCE's inherent operating risks include such matters as the risks of human performance, workforce capabilities, public opposition to infrastructure projects, delays, environmental mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, and interruptions in necessary supplies.

424. The statements referenced in ¶423 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid methodology to evaluate

pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with the Thomas and Woolsey Fires; (ix) the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) consequently, the Company did not elevate operational risks; (xii) the Company classified major categories of spending as safety related, even though they related to issues of customer satisfaction or electric service reliability, rather than safety; (xiii) the Company had already been told by SED that it should not conflate safety and reliability; and (xiv) as a result, the Company's public statements were materially false and misleading at all relevant times.

425. In addition, the risk factors referenced in ¶423 above relating to aging infrastructure were false and misleading because at the time the allegedly prospective risks were discussed, they had already: (i) come to fruition, albeit on a limited basis, with the July-August 2015 Long Beach outages, which affected to 30,000 customers, caused fires in several underground structures, and resulted in explosions that blew manhole covers into the air; and (ii) materialized via the Thomas Fire, Montecito mudslides, and the Woolsey Fire. Moreover, the SCE Defendants knew their claimed infrastructure investments were insufficient to mitigate the cited risks for the reasons described in ¶424 above.

426. The SCE Defendants acknowledged in 2018 10-K that their business may result in damage to private and public property, as well as injuries to bystanders, stating in relevant part:

> ***The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public.***
>
> Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines or if equipment malfunctions. ***In addition, the risks associated with the operation of transmission and distribution assets and power generating facilities include public and employee safety issues and the risk of utility assets causing or contributing to wildfires. Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant***. No assurance can be given that future losses will not exceed the limits of SCE's or its contractors' insurance coverage. The CPUC has increased its focus on public safety with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $100,000 per violation per day (capped at a maximum of $8 million), pursuant to the CPUC's jurisdiction for violations of safety rules found in statutes, regulations, and the CPUC's General Orders. ***Such penalties and liabilities could be significant and materially affect SCE's liquidity and results of operations.***

427. The risk factors referenced in ¶426 above relating to prospective citations and fines were false and misleading come to fruition, albeit on a limited basis, with respect to: (i) failing to maintain electrical equipment that injured three U.S. Marines in Twentynine Palms in 2015; (ii) the Potrero Fire of November 2015, in which the Company was cited for failing to replace or reinforce an unsafe utility pole; (iii) the fatal electrocution at Edison's Whittier facility, for which Edison was fined $50,000 on February 12, 2016; (iv) Edison's numerous citations for safety violations between April 4, 2016 and February 9, 2018; and (v) the Liberty Fire. In addition, (vi) the risks had already materialized via the Thomas Fire, Montecito mudslides, and the Woolsey Fire; and (vii) the SCE Defendants were directly aware, no later than December 27, 2017, due to meetings between investigators and SCE representatives, that Edison had started the

Thomas Fire. At all relevant times, the SCE Defendants knew their potential liability extended well beyond "inherent risks" to include risks created by the Company's own reckless disregard of safety, as described in ¶424 above.

428. The 2018 10-K also discussed various risks to the Company as a result of wildfire related liabilities, including its possible inability to pay distributions to investors who purchased in the Offering:

> ***Damage claims against SCE for wildfire-related losses may materially affect SCE's financial condition and results of operations.***
>
> ***Prolonged drought conditions and shifting weather patterns in California resulting from climate change as well as increased tree mortality rates have increased the duration of the wildfire season and the risk of severe wildfire events. Severe wildfires and increased urban development in high fire risk areas in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of utility practices and/or the failure of electric and other utility equipment. California courts have previously found utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. The rationale generally stated by these courts for applying this theory to investor-owned utilities is that property losses resulting from a public improvement, such as the distribution of electricity, can be spread across the larger community that benefited from such improvement.*** However, in December 2017, the CPUC issued a decision denying an investor-owned utility's request to include in its rates uninsured wildfire-related costs arising from several 2007 fires, finding that the investor-owned utility did not prudently manage and operate its facilities prior to or at the outset of the 2007 wildfires. An inability to recover uninsured wildfire-related costs could materially affect SCE's business, financial condition and results of operations. ***For example, if SCE is found liable for damages related to the 2017/2018 Wildfire/Mudslide Events, and SCE is unable to, or believes that it will be unable to, recover those damages through insurance or electric rates, SCE may not have sufficient cash or equity to pay dividends or may be restricted from declaring such dividends because it does not***

> ***meet CPUC or California law requirements related to the declaration of dividends*** . . . .

429. The 2018 10-K further stated that: "***[a]ny potential liability of SCE for damages related to the 2017/2018 Wildfire/Mudslide Events will depend on a number of factors, including whether SCE is determined to have substantially caused, or contributed to, the damages and whether parties seeking recovery of damages will be required to show negligence in addition to causation***."

430. The statements referenced in ¶¶428-29 above were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017, due to meetings between investigators and SCE representatives; (ii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iii) Edison had caused the Woolsey Fire; (iv) Edison's liability for the Thomas Fire, Montecito Mudslides, and Woolsey Fire was not merely speculative, but highly likely; (v) Edison's liability would not be limited by any requirement that negligence be shown, given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;

- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas and Woolsey Fires, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas and Woolsey Fires; and
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations;

(vi) consequently, Edison had not prudently managed and operated its facilities prior to the Thomas and Woolsey Fires, and therefore understood the extent of its potential liability; and (vii) as a result, the Company's public statements were materially false and misleading at all relevant times.

431. The 2018 10-K also discussed wildfire/mudslide events in southern California in 2017-2018, and stated, in relevant part:

> **Southern California Wildfires and Mudslide**
>
> Approximately 35% of SCE's service territory is in areas identified as high fire risk by SCE. ***Multiple factors have contributed to increased wildfires,***

> ***faster progression of wildfires and the increased damage from wildfires across SCE's service territory*** and throughout California. ***These include the buildup of dry vegetation in areas severely impacted by years of historic drought, lack of adequate clearing of hazardous fuels by responsible parties, higher temperatures, lower humidity, and strong Santa Ana winds***. ***At the same time that wildfire risk has been increasing in Southern California, residential and commercial development has occurred and is occurring in some of the highest-risk areas***. ***Such factors can increase the likelihood and extent of wildfires***.
>
> ….
>
> Multiple lawsuits related to the Thomas Fire and the Woolsey Fire have been initiated against SCE and Edison International. ***Some of the Thomas Fire-related lawsuits claim that SCE and Edison International have responsibility for the damages caused by the Montecito Mudslides based on a theory that SCE has responsibility for the Thomas Fire*** ….
>
> ***Edison International and SCE will seek to offset any actual losses realized in connection with the 2017/2018 Wildfire/Mudslide Events*** with recoveries from insurance policies in place at the time of the events and, to the extent actual losses exceed insurance, ***through electric rates*** …. SCE believes that in light of the CPUC's decision in cost recovery proceedings involving SDG&E, arising from a 2007 wildfire in SDG&E's service area, there is substantial uncertainty regarding how the CPUC will interpret and apply its prudency standard to an investor-owned utility in future wildfire cost-recovery proceedings. ***Accordingly, while the CPUC has not made a determination regarding SCE's prudency relative to any of the 2017/2018 Wildfire/Mudslide Events, SCE is unable to conclude, at this time, that uninsured CPUC-jurisdictional wildfire-related costs are probable of recovery through electric rates.***

432. The statements referenced in ¶431 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) they knew that the risk of wildfires in the Company's territory extended well beyond prolonged drought conditions, "lack of

adequate clearing," climate-related factors, stronger winds, and residential and commercial development to include risks created by the Company's own reckless disregard of safety; (ii) Edison's responsibility for the Thomas Fire was not a "theory" because Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017; (iii) Edison would be substantially limited in its ability to offset wildfire-related losses by raising rates, given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas and Woolsey Fires, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter*

alia, the Thomas and Woolsey Fires; and

- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations;

(iv) consequently, Edison had not prudently managed and operated its facilities prior to the Thomas and Woolsey Fires, and therefore understood the extent of its potential liability; and (v) as a result, the Company's public statements were materially false and misleading at all relevant times.

433. In a section of the 2018 10-K titled, "Internal Review," the SCE Defendants stated, in relevant part:

> *Thomas Fire*
>
> ….
>
> Based on currently available information, SCE believes that the Thomas Fire had at least two separate ignition points, one near Koenigstein Road in the City of Santa Paula and the other in the Anlauf Canyon area of Ventura County. With respect to the Koenigstein Road ignition point, witnesses have reported that a fire ignited in the vicinity of an SCE power pole and SCE later learned of a downed electrical wire at this location. ***SCE believes that its equipment was associated with this ignition*** …. ***SCE is continuing to assess the progression of the fire from the Koenigstein Road ignition point and the extent of damages that may be attributable to that ignition***. ***At this time, based on available information, SCE has not determined whether the ignition in the Anlauf Canyon area involved SCE equipment*** ….
>
> *Montecito Mudslides*
>
> ***SCE's internal review also includes inquiry into whether the Thomas Fire proximately caused or contributed to the Montecito Mudslides***, the source of ignition of the portion of the Thomas Fire that burned through the Montecito area and other factors that potentially contributed to the losses that resulted from the Montecito Mudslides …. ***At this time, based on available information, SCE has not been able to determine the source of***

> ***ignition of the portion of the Thomas Fire that burned within the Montecito area. In the event that SCE is determined to have caused the fire that spread to the Montecito area, SCE cannot predict whether, if fully litigated, the courts would conclude that the Montecito Mudslides were caused or contributed to by the Thomas Fire or that SCE would be liable for some or all of the damages caused by the Montecito Mudslides.***
>
> *Woolsey Fire*
>
> SCE's internal review into the facts and circumstances of the Woolsey Fire is ongoing …. ***SCE is aware of witnesses who saw fire in the vicinity of SCE's equipment at the time the fire was first reported*** ….

434. The statements referenced in ¶433 above were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, and SCE's Castro Circuit was the point of origin of both of the Thomas Fire's ignition points, facts known to the SCE Defendants no later than December 27, 2017; (ii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iii) they were not merely "aware of witnesses" to the outbreak of the Woolsey Fire, because the witness who reported the Woolsey Fire was an employee of Edison's own contractor, thereby placing the SCE Defendants in a superior position to understand the fire's causes; and (iv) as a result, the Company's public statements were materially false and misleading at all relevant times.

Q1 2019 10-Q

435. On April 30, 2019, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q1 2019 10-Q"). The Q1 2019 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for

wildfires, stating in relevant part:

> **Southern California Wildfires and Mudslides**
>
> Approximately 35% of SCE's service territory is in areas identified as high fire risk by SCE. ***Multiple factors have contributed to increased wildfires, faster progression of wildfires and the increased damage from wildfires across SCE's service territory*** and throughout California. ***These include the buildup of dry vegetation in areas severely impacted by years of historic drought, lack of adequate clearing of hazardous fuels by responsible parties, higher temperatures, lower humidity, and strong Santa Ana winds***. ***At the same time that wildfire risk has been increasing in Southern California, residential and commercial development has occurred and is occurring in some of the highest-risk areas***. ***Such factors can increase the likelihood and extent of wildfires***.
>
> ….
>
> In March 2019, the VCFD and CAL FIRE issued separate reports finding that the ***Thomas Fire and the Koenigstein Fire*** were each caused by SCE equipment. At this time, based on available information, SCE has not determined whether its equipment caused the Thomas Fire. ***Based on publicly available radar data showing a smoke plume in the Anlauf Canyon area emerging in advance of the start time of the Thomas Fire indicated in the Thomas Fire report, SCE believes that the Thomas Fire started at least 12 minutes prior to any issue involving SCE's system and at least 15 minutes prior to the start time indicated in the report***. SCE has previously disclosed that SCE believed its equipment was associated with the ignition of the ***Koenigstein Fire***. SCE is continuing to assess the progression of the ***Thomas and Koenigstein Fires*** and the extent of damages that may be attributable to each fire.
>
> Multiple lawsuits related to the ***Thomas and Koenigstein Fires*** and the Woolsey Fire have been initiated against SCE and Edison International. Some of the ***Thomas and Koenigstein Fires*** lawsuits claim that SCE and Edison International have responsibility for the damages caused by the Montecito Mudslides based on a theory that SCE has responsibility for the ***Thomas and/or Koenigstein Fires*** and that the ***Thomas and/or Koenigstein Fires*** proximately caused the Montecito Mudslides.
>
> ….
>
> ***Edison International and SCE will seek to offset any actual losses realized in***

> ***connection with the 2017/2018 Wildfire/Mudslide Events*** with recoveries from insurance policies in place at the time of the events and, to the extent actual losses exceed insurance, ***through electric rates*** …. SCE believes that, in light of the CPUC's decision in a cost recovery proceeding involving SDG&E arising from several 2007 wildfires in SDG&E's service area, there is substantial uncertainty regarding how the CPUC will interpret and apply its prudency standard to an investor-owned utility in future wildfire cost-recovery proceedings. ***Accordingly, while the CPUC has not made a determination regarding SCE's prudency relative to any of the 2017/2018 Wildfire/Mudslide Events, SCE is unable to conclude, at this time, that uninsured CPUC-jurisdictional wildfire-related costs are probable of recovery through electric rates.***

436. The statements referenced in ¶435 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) they knew that the risk of wildfires in the Company's territory extended well beyond prolonged drought conditions, "lack of adequate clearing," climate-related factors, stronger winds, and residential and commercial development to include risks created by the Company's own reckless disregard of safety; (ii) Edison's responsibility for the Thomas Fire was not a "theory" because Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017; (iii) as of December 27, 2017, the SCE Defendants knew that both ignition points of the Thomas Fire had been linked to SCE's Castro Circuit, and were therefore not two entirely separate fires ("the Thomas and/or Koenigstein Fires") with divergent causes and culprits; (iv) Edison would be substantially limited in its ability to offset wildfire-related losses by raising rates, given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached

wires;

- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas and Woolsey Fires, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas and Woolsey Fires; and
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations;

(v) consequently, Edison had not prudently managed and operated its facilities prior to the Thomas and Woolsey Fires, and therefore understood the extent of its potential liability; and (vi) as a result, the Company's public statements were materially false and misleading at all relevant times.

437. In a section of the Q1 2019 10-Q titled, "External Investigations and

Internal Review," the Company stated, in relevant part:

> *Thomas Fire*
>
> ….
>
> On March 13, 2019, the VCFD and CAL FIRE issued a report concluding, after ruling out other possible causes, that the Thomas Fire was started by SCE power lines coming into contact during high winds, resulting in molten metal falling to the ground. However, the report does not state that molten metal was found on the ground in that location during their investigation. ***At this time, based on available information, SCE has not determined whether its equipment caused the Thomas Fire***. Based on publicly available radar data showing a smoke plume in the Anlauf Canyon area emerging in advance of the report's indicated start time, ***SCE believes that the Thomas Fire started at least 12 minutes prior to any issue involving SCE's system and at least 15 minutes prior to the start time indicated in the report. SCE is continuing to assess the progression of the Thomas Fire and the extent of damages that may be attributable to that fire***
>
> ….
>
> *Montecito Mudslides*
>
> ***SCE's internal review includes inquiry into whether the Thomas and/or Koenigstein Fires proximately caused or contributed to the Montecito Mudslides***, whether, and to what extent, the Thomas and/or Koenigstein Fires were responsible for the damages in the Montecito area and other factors that potentially contributed to the losses that resulted from the Montecito Mudslides …. ***At this time, based on available information, SCE has not been able to determine whether the Thomas Fire or the Koenigstein Fire, or both, were responsible for the damages in the Montecito area. In the event that SCE is determined to have caused the fire that spread to the Montecito area, SCE cannot predict whether, if fully litigated, the courts would conclude that the Montecito Mudslides were caused or contributed to by the Thomas and/or Koenigstein Fires or that SCE would be liable for some or all of the damages caused by the Montecito Mudslides***.
>
> *Woolsey Fire*

> SCE's internal review into the facts and circumstances of the Woolsey Fire is ongoing …. ***SCE is aware of witnesses who saw fire in the vicinity of SCE's equipment at the time the fire was first reported*** ….

438. The statements referenced in ¶437 above were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, and SCE's Castro Circuit was the point of origin of both of the Thomas Fire's ignition points, facts known to the SCE Defendants no later than December 27, 2017; (ii) as of December 27, 2017, the SCE Defendants knew that both ignition points of the Thomas Fire had been linked to SCE's Castro Circuit, and were therefore not two entirely separate fires ("the Thomas and/or Koenigstein Fires") with divergent causes and culprits; (iii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iv) they were not merely "aware of witnesses" to the outbreak of the Woolsey Fire, because the witness who reported the Woolsey Fire was an employee of Edison's own contractor, thereby placing the SCE Defendants in a superior position to understand the fire's causes; and (v) as a result, the Company's public statements were materially false and misleading at all relevant times.

439. In a section of the Q1 2019 10-Q titled "Recovery of Wildfire-Related Costs," the Company stated that:

> SB 901 requires investor-owned utilities to prepare annually, for CPUC approval, ***wildfire risk mitigation plans, and compliance with an approved plan is one of the factors that the CPUC can consider in addressing cost recovery***. On February 6, 2019, in compliance with SB 901, SCE filed its wildfire mitigation plan for 2019. ***While SCE takes the position in its wildfire mitigation plan that substantial compliance with the plan, once approved, will demonstrate that SCE prudently operated its system and***

met the CPUC's prudent manager standard regarding wildfire risk mitigation, the CPUC may not agree with SCE's position.

440. The statements referenced in ¶439 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison would be substantially limited in its ability to meet the CPUC's prudence manager standard for cost recovery purposes, given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;
- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas and Woolsey Fires, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could

result in catastrophic financial consequences for the Company;

- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas and Woolsey Fires; and
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations;

(ii) Edison understated the extent of its potential wildfire liability; (iii) Edison overstated its ability to recover wildfire-related costs; and (iv) as a result, the Company's public statements were materially false and misleading at all relevant times.

<u>Q2 2019 10-Q</u>

441. On July 25, 2019, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q2 2019 10-Q"). The Q2 2019 10-Q discussed the risks posed to the Company's financial condition and operations should they be responsible for wildfires, stating in relevant part:

> **Southern California Wildfires and Mudslides**
>
> …. ***Multiple factors have contributed to increased wildfires, faster progression of wildfires and the increased damage from wildfires across SCE's service territory*** and throughout California. ***These include the buildup of dry vegetation in areas severely impacted by years of historic drought, lack of adequate clearing of hazardous fuels by responsible parties, higher temperatures, lower humidity, and strong Santa Ana winds***. ***At the same time that wildfire risk has been increasing in Southern California, residential and commercial development has occurred and is occurring in some of the highest-risk areas***. ***Such factors can increase the likelihood and extent of wildfires***.
>
> ….
>
> In March 2019, the VCFD and CAL FIRE issued separate reports finding that the ***Thomas Fire and the Koenigstein Fire*** were each caused by SCE equipment. At this time, based on available information, SCE has not

> determined whether its equipment caused the Thomas Fire. ***Based on publicly available radar data showing a smoke plume in the Anlauf Canyon area emerging in advance of the start time of the Thomas Fire indicated in the Thomas Fire report, SCE believes that the Thomas Fire started at least 12 minutes prior to any issue involving SCE's system and at least 15 minutes prior to the start time indicated in the report***. SCE has previously disclosed that SCE believed its equipment was associated with the ignition of the ***Koenigstein Fire***. SCE is continuing to assess the progression of the ***Thomas and Koenigstein Fires*** and the extent of damages that may be attributable to each fire.
>
> Multiple lawsuits related to the ***Thomas and Koenigstein Fires*** and the Woolsey Fire have been initiated against SCE and Edison International. Some of the ***Thomas and Koenigstein Fires*** lawsuits claim that SCE and Edison International have responsibility for the damages caused by the Montecito Mudslides based on a theory that SCE has responsibility for the ***Thomas and/or Koenigstein Fires*** and that the ***Thomas and/or Koenigstein Fires*** proximately caused the Montecito Mudslides.
>
> ….
>
> ***Edison International and SCE will seek to offset any actual losses realized in connection with the 2017/2018 Wildfire/Mudslide Events*** with recoveries from insurance policies in place at the time of the events and, to the extent actual losses exceed insurance, ***through electric rates*** …. SCE believes that, in light of the CPUC's decision in a cost recovery proceeding involving SDG&E arising from several 2007 wildfires in SDG&E's service area, there is substantial uncertainty regarding how the CPUC will interpret and apply its prudency standard to an investor-owned utility in future wildfire cost-recovery proceedings for fires ignited prior to July 12, 2019. ***Accordingly, while the CPUC has not made a determination regarding SCE's prudency relative to any of the 2017/2018 Wildfire/Mudslide Events, SCE is unable to conclude, at this time, that uninsured CPUC-jurisdictional wildfire-related costs are probable of recovery through electric rates.***

442. The statements referenced in ¶441 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company’s business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading

statements and/or failed to disclose that: (i) they knew that the risk of wildfires in the Company's territory extended well beyond prolonged drought conditions, "lack of adequate clearing," climate-related factors, stronger winds, and residential and commercial development to include risks created by the Company's own reckless disregard of safety; (ii) Edison's responsibility for the Thomas Fire was not a "theory" because Edison had caused the Thomas Fire, a fact known to the SCE Defendants no later than December 27, 2017; (iii) as of December 27, 2017, the SCE Defendants knew that both ignition points of the Thomas Fire had been linked to SCE's Castro Circuit, and were therefore not two entirely separate fires ("the Thomas and/or Koenigstein Fires") with divergent causes and culprits; (iv) regardless of *when* the wildfires in question occurred, Edison would be substantially limited in its ability to offset wildfire-related losses by raising rates, given that:

- the Company completed numerous work orders past their scheduled date of corrective action;
- the Company failed to replace or reinforce unsafe utility poles and/or attached wires;
- the Company failed to mitigate interference with equipment by vegetation;
- the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC;
- the Company failed to utilize a statistically-valid methodology to evaluate pole-loading;
- the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed;
- the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure;

- the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas and Woolsey Fires, despite knowing that their pole stock was particularly vulnerable in high wind events, and that failure to de-energize could result in catastrophic financial consequences for the Company;
- the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had materialized with, *inter alia*, the Thomas and Woolsey Fires; and
- the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies;
- the Company was in violation of state law and regulations;

(v) consequently, Edison had not prudently managed and operated its facilities prior to the Thomas and Woolsey Fires, and therefore understood the extent of its potential liability; and (vi) as a result, the Company's public statements were materially false and misleading at all relevant times.

443. In a section of the Q2 2019 10-Q titled, "External Investigations and Internal Review," the Company stated, in relevant part:

> *Thomas Fire*
>
> ….
>
> On March 13, 2019, the VCFD and CAL FIRE issued a report concluding, after ruling out other possible causes, that the Thomas Fire was started by SCE power lines coming into contact during high winds, resulting in molten metal falling to the ground. However, the report does not state that molten metal was found on the ground in that location during their investigation. ***At this time, based on available information, SCE has not determined whether its equipment caused the Thomas Fire***. Based on publicly available radar data showing a smoke plume in the Anlauf Canyon area emerging in advance of the report's indicated start time, ***SCE believes that the Thomas Fire started at least 12 minutes prior to any issue involving SCE's system and at least 15 minutes prior to the start time indicated in the report. SCE is continuing to assess the progression of the***

> ***Thomas Fire and the extent of damages that may be attributable to that fire***….
>
> *Montecito Mudslides*
>
> ***SCE's internal review includes inquiry into whether the Thomas and/or Koenigstein Fires proximately caused or contributed to the Montecito Mudslides***, whether, and to what extent, the Thomas and/or Koenigstein Fires were responsible for the damages in the Montecito area and other factors that potentially contributed to the losses that resulted from the Montecito Mudslides …. ***At this time, based on available information, SCE has not been able to determine whether the Thomas Fire or the Koenigstein Fire, or both, were responsible for the damages in the Montecito area. In the event that SCE is determined to have caused the fire that spread to the Montecito area, SCE cannot predict whether, if fully litigated, the courts would conclude that the Montecito Mudslides were caused or contributed to by the Thomas and/or Koenigstein Fires or that SCE would be liable for some or all of the damages caused by the Montecito Mudslides***.
>
> *Woolsey Fire*
>
> SCE's internal review into the facts and circumstances of the Woolsey Fire is ongoing …. ***SCE is aware of witnesses who saw fire in the vicinity of SCE's equipment at the time the fire was first reported*** ….

444. The statements referenced in ¶443 above were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) Edison had caused the Thomas Fire, and SCE's Castro Circuit was the point of origin of both of the Thomas Fire's ignition points, facts known to the SCE Defendants no later than December 27, 2017; (ii) as of December 27, 2017, the SCE Defendants knew that both ignition points of the Thomas Fire had been linked to SCE's Castro Circuit, and were therefore not two entirely separate fires ("the Thomas and/or Koenigstein Fires") with divergent

causes and culprits; (iii) Edison had caused the Montecito Mudslides, which were a direct consequence of the Thomas Fire caused by Edison; (iv) they were not merely "aware of witnesses" to the outbreak of the Woolsey Fire, because the witness who reported the Woolsey Fire was an employee of Edison's own contractor, thereby placing the SCE Defendants in a superior position to understand the fire's causes; and (v) as a result, the Company's public statements were materially false and misleading at all relevant times.

The Truth Emerges

The Thomas Fire

445. The Thomas Fire was a partial materialization of the risks concealed by the Company's failure to maintain its electrical infrastructure and otherwise mitigate the risk of wildfires. Accordingly, Edison shares plunged $10.26, nearly 15%, to close at $70.00 on December 5, 2017 from the previous day's closing price of $80.26, wiping out more than $3 billion in market value, on the market's understanding – later confirmed by Cal Fire – that SCE had caused the Thomas Fire:

446. On December 11, 2017, after the market closed, SCE issued a press release entitled "Southern California Edison Responds to Area Fires." Buried within the last paragraph was a significant disclosure, "***SCE believes the investigations now include the possible role of its facilities***."

447. Upon this partial confirmation of the market's informed reaction to the Thomas Fire, Edison's stock price fell $4.40 per share, or approximately 6%, to close at $68.58 per share on December 12, 2017.

The Woolsey Fire

448. On November 9, 2018, the Company issued a press release providing an update on the Woolsey Fire, which obliquely – and misleadingly – referred to "an outage in the vicinity" of the fire. In fact, the circuit interruption in question had occurred at ground zero of the fire. This was the first indication that Edison had caused the Woolsey Fire:

> ROSEMEAD, Calif., November 9, 2018 — Southern California Edison's Emergency Operations Center has mobilized resources and crews to assist first responders and to begin restoring power in communities affected by the wildfires in Ventura and Los Angeles counties as soon as fire officials say it is safe.
>
> ***The company's top priority continues to be the safety of customers, employees and communities.*** SCE is working closely with first responder partners and is prepared to safely and quickly restore power as soon as possible.
>
> As of 5:45 p.m., 23,000 customers were without power, with 20,000 of them in Los Angeles County, many affected by the fires. SCE is currently monitoring several fires impacting customers within its service territory, including the Hill Fire in Ventura County and the Woolsey Fire in Ventura and Los Angeles counties, which has moved into the Malibu area.
>
> ***The fires have damaged SCE equipment and lines and caused outages in fire-affected areas.*** Once it is safe to do so and access has been granted,

> SCE's damage assessment teams will determine what equipment and repairs are needed before repairs can begin. SCE air patrols may also be required to fully assess damage caused by the fires in more remote areas, but that access is limited due to flight restrictions for fire-fighting operations.
>
> ***SCE has been in communication with the California Public Utilities Commission with respect to these fires and has submitted an initial electric safety incident report on the Woolsey Fire reporting an outage in the vicinity. The information in the report is preliminary. There has been no determination of origin or cause of either wildfire***. SCE will fully cooperate with any investigations.
>
> * * *
>
> **Edison's Efforts at Managing the Wildfire Threat in California**
>
> ***Safety is the company's top priority and a core value for SCE***. Our employees work vigilantly year-round to strengthen the electric system and protect the public and our employees against a variety of natural and man-made threats. ***We have long taken substantial steps to reduce the risk of wildfires in our service territory and*** continue to look for ways to enhance our operational practices and infrastructure. ***SCE employs design and construction standards, vegetation management practices and other operational practices to mitigate wildfire risk and has collaborative partnerships with fire agencies to maintain fire safety.***

449. The statements referenced in ¶448 were materially false and misleading because the SCE Defendants made false and/or misleading statements, as well as failed to disclose material adverse facts about the Company's business, operational and compliance policies. Specifically, the SCE Defendants made false and/or misleading statements and/or failed to disclose that: (i) the Company completed numerous work orders past their scheduled date of corrective action; (ii) the Company failed to replace or reinforce unsafe utility poles and/or attached wires; (iii) the Company failed to mitigate interference with equipment by vegetation; (iv) the Company failed to assess, remediate, repair, and/or replace aging and/or overloaded poles as prescribed by CPUC; (v) the Company failed to utilize a statistically-valid

methodology to evaluate pole-loading; (vi) the Company relied on software updates that had not been independently verified and validated to allow for fewer pole assessments than were actually needed; (vii) the Company deployed a "run-to-failure" maintenance model that consciously allowed for equipment failure; (viii) the Company's noncompliant electricity networks created a significantly heightened risk of wildfires in California, which had partially materialized with the Thomas and Woolsey Fires; (ix) the Company failed to properly assess the risks of its equipment, and therefore had no strategy in place to remedy the above-discussed deficiencies; (x) the Company was in violation of state law and regulations; (xi) the Company failed to de-energize in high-wind, high-fire scenarios, including the Thomas Fire, despite:

- knowing that their pole stock was particularly vulnerable in high wind events,
- knowing that failure to de-energize could result in catastrophic financial consequences for the Company; and
- reassuring investors that they would do so in such circumstances;

(xii) consequently, the Company had not "taken substantial steps to reduce the risk of wildfires in [its] service territory," "mitigate[ed] wildfire risk," or "maintain[ed] fire safety"; (xiii) as a result, the Company's public statements were materially false and misleading at all relevant times.

450. Between November 10 and 11, 2018, it was gradually revealed by local news sources that SCE had filed an incident report with CPUC on the evening of November 8, stating that there was an interruption to SCE's Big Rock 16 kV circuit near its Chatsworth substation two minutes before the first report of a fire came in. The substation is near E Street and Alfa Road in Ventura County — which is also where Cal Fire says the Woolsey Fire began.

451. On November 12, 2018, CPUC launched an investigation into Edison's subsidiary, SCE, in order to "assess the compliance of electrical facilities with

applicable rules and regulations in fire-impacted areas." According to CPUC – and echoing earlier reports regarding the November 8 incident report – electrical infrastructure may have suffered malfunctions near ground zero of the blazes.

452. Specifically, it was reported that on the day the fires began, SCE issued an alert to CPUC that a substation circuit near the Woolsey Fire origin "relayed," or sensed a disturbance on the circuit, just two minutes before Cal Fire said that the devastating fire began.

453. Following the November 10-12 disclosures of the November 8, 2018 incident report and CPUC's announcement, Edison's stock price fell $7.44 per share, or more than 12%, to close at $53.56 per share on November 12, 2018. Over the following days, as the Hill and Woolsey Fires continued to burn, Edison's stock price continued to fall, closing at $47.19 on November 15, 2018, a total drop of 32% from its price prior to CPUC's announcement. The risks concealed by the Company's failure to maintain its electrical infrastructure and otherwise mitigate the risk of wildfires had further materialized.

454. On October 29, 2019, the Company filed a Quarterly Report on Form 10-Q with the SEC (the "Q3 2019 10-Q"). The Q3 2019 10-Q made fresh disclosures regarding SCE's role in causing the Woolsey Fire, and stated, in relevant part:

> SCE has received a non-final redacted draft of a report from the [Ventura County Fire Department ("VCFD")] subject to a protective order in the litigation related to the Woolsey fire and, other than the information disclosed in this Form 10-Q, is not authorized to release the report or its contents to the public at this time. ***The draft report states that the VCFD investigation team determined that electrical equipment owned and operated by SCE was the cause of the Woolsey Fire. Absent additional evidence, SCE believes that it is likely that its equipment was associated with the ignition of the Woolsey Fire***.

455. The same day the SCE Defendants held a conference call with investors

and analysts (the "Q3 2019 Earnings Call"), during which Defendant Pizarro declined to answer an analyst's question regarding "any violations found in the report" provided to SCE.

456. Following the SCE Defendants' disclosure that they had caused the Woolsey Fire, Edison's stock price declined by $3.24 per share, or more than 5%, to close at $62.16 per share on October 30, 2019.

CLASS ACTION ALLEGATIONS

457. Plaintiffs bring this action as a class action pursuant to Federal Rule of Civil Procedure 23(a) and (b)(3) on behalf of a Class, consisting of all those who purchased or otherwise acquired Edison securities during the Class Period (the "Class"); and were damaged upon the revelation of the alleged corrective disclosures and/or materialization of known risks. Excluded from the Class are Defendants herein, the officers and directors of the Company, at all relevant times, members of their immediate families and their legal representatives, heirs, successors or assigns and any entity in which Defendants have or had a controlling interest.

458. The members of the Class are so numerous that joinder of all members is impracticable. Throughout the Class Period, Edison securities were actively traded on the NYSE. While the exact number of Class members is unknown to Plaintiffs at this time and can be ascertained only through appropriate discovery, Plaintiffs believes that there are hundreds or thousands of members in the proposed Class. Record owners and other members of the Class may be identified from records maintained by Edison or its transfer agent and may be notified of the pendency of this action by mail, using the form of notice similar to that customarily used in securities class actions.

459. Plaintiffs' claims are typical of the claims of the members of the Class as all members of the Class are similarly affected by Defendants' wrongful conduct in violation of federal law that is complained of herein.

460. Plaintiffs will fairly and adequately protect the interests of the members of the Class and has retained counsel competent and experienced in class and securities litigation. Plaintiffs have no interests antagonistic to or in conflict with those of the Class.

461. Common questions of law and fact exist as to all members of the Class and predominate over any questions solely affecting individual members of the Class. Among the questions of law and fact common to the Class are:

- whether the federal securities laws were violated by Defendants' acts as alleged herein;
- whether statements made by Defendants to the investing public during the Class Period misrepresented material facts about the business, operations and management of Edison;
- whether the Individual Defendants caused Edison to issue false and misleading financial statements during the Class Period;
- whether Defendants acted knowingly or recklessly in issuing false and misleading financial statements;
- whether the prices of Edison securities during the Class Period were artificially inflated because of the Defendants' conduct complained of herein; and
- whether the members of the Class have sustained damages and, if so, what is the proper measure of damages.

462. A class action is superior to all other available methods for the fair and efficient adjudication of this controversy since joinder of all members is impracticable. Furthermore, as the damages suffered by individual Class members may be relatively small, the expense and burden of individual litigation make it impossible for members of the Class to individually redress the wrongs done to them. There will be no

difficulty in the management of this action as a class action.

463. Plaintiffs will rely, in part, upon the presumption of reliance established by the fraud-on-the-market doctrine in that:

- Defendants made public misrepresentations or failed to disclose material facts during the Class Period;
- the omissions and misrepresentations were material;
- Edison securities are traded in an efficient market;
- the Company's shares were liquid and traded with moderate to heavy volume during the Class Period;
- the Company traded on the NYSE and was covered by multiple analysts;
- the misrepresentations and omissions alleged would tend to induce a reasonable investor to misjudge the value of the Company's securities; and
- Plaintiffs and members of the Class purchased, acquired and/or sold Edison securities between the time the Defendants failed to disclose or misrepresented material facts and the time the true facts were disclosed, without knowledge of the omitted or misrepresented facts.

464. Based upon the foregoing, Plaintiffs and the members of the Class are entitled to a presumption of reliance upon the integrity of the market.

465. Alternatively, Plaintiffs and the members of the Class are entitled to the presumption of reliance established by the Supreme Court in *Affiliated Ute Citizens of the State of Utah v. United States*, 406 U.S. 128, 92 S. Ct. 2430 (1972), as Defendants omitted material information in their Class Period statements in violation of a duty to disclose such information, as detailed above.

COUNT I
(Violations of Section 11 of the Exchange Act Against Defendants Edison, SCE, SCE Trust VI, Payne, Petmecky, Erickson, and the Underwriter Defendants)

466. Plaintiffs repeat and reallege each and every allegation contained above as if fully set forth herein, except any allegation of fraud, recklessness or intentional misconduct.

467. This claim is premised on strict liability under Section 11 of the Securities Act, and does not assert that Defendants acted with fraudulent intent.

468. This claim is asserted by Plaintiffs against Defendants Edison, SCE, SCE Trust VI, Payne, Petmecky, Erickson, and the Underwriter Defendants on behalf of all persons who acquired shares traceable to the Offering, in which the shares issued pursuant to the Offering Documents were sold.

469. Defendants Payne, Petmecky, and Erickson are strictly liable under the Securities Act as signatories of the Registration Statement for the misrepresentations and omissions contained therein, as identified in ¶¶346-51 above. Defendant Payne is further strictly liable under the Securities Act for misrepresentations and omissions in the Registration Statement because he was a director of the Company at the time of its filing.

470. Edison is strictly liable as an Issuer under the Securities Act for the misrepresentations and omissions it made in the Registration Statement, as identified in ¶¶346-51 above.

471. SCE is strictly liable as an Issuer under the Securities Act for the misrepresentations and omissions it made in the Registration Statement, as identified in ¶¶346-51 above.

472. SCE Trust VI is strictly liable as an Issuer under the Securities Act for the misrepresentations and omissions it made in the Registration Statement, as identified in

¶¶346-51 above.

473. The Underwriter Defendants are strictly liable under the Securities Act as named underwriters for the misrepresentations and omissions made in the Registration Statement, as identified in ¶¶346-51 above.

474. None of the Defendants named in ¶468 above conducted a reasonable investigation or possessed a reasonable basis for the belief that the statements contained in the Registration Statement and identified in ¶¶346-51 above were true, were without omissions of material fact, and were not misleading.

475. By reason of the conduct alleged herein, each of the Defendants named in ¶468 above has violated Section 11 of the Securities Act.

476. Plaintiffs and the Class have sustained enormous damages because the value of their Edison securities has declined precipitously.

477. At the time of their purchases, Plaintiffs and the Class were without knowledge of the wrongful conduct alleged herein, and could not have reasonably discovered those facts more than one year prior to the filing of the initial complaint in this action. The initial complaint was filed within three years of the time that Edison offered the shares covered by the Registration Statement to the investing public.

478. By virtue of the foregoing, Plaintiffs and the other Class members are entitled to damages under Section 11 as measured by the provisions of Section 11(e), from the Defendants named in ¶468 above and each of them, jointly and severally.

COUNT II

(Violations of Section 12(a)(2) of the Securities Act Against the Underwriter Defendants)

479. Plaintiffs repeat and reallege each and every allegation contained above as if fully set forth herein, except any allegation of fraud, recklessness or intentional misconduct. This claim is premised on the remedies available under Section 12 of the Securities Act, and does not assert that Defendants acted with fraudulent intent.

480. This claim is asserted by Plaintiffs against the Underwriter Defendants, on behalf of all persons who acquired Edison securities pursuant to the Offering.

481. By means of the Registration Statement and Prospectus, each of the Underwriter Defendants offered, promoted, and sold Edison securities in the Offering, and therefore were liable under Section 12(a)(2) for the misrepresentations and omissions contained in the Prospectus and repeated in the Registration Statement.

482. None of the Underwriter Defendants named herein conducted a reasonable investigation or possessed a reasonable basis for the belief that the statements contained in the Registration Statement and Prospectus, and identified in ¶¶346-51 above were true, were without omissions of material fact, and were not misleading.

483. By reason of the conduct alleged herein, each of the Underwriter Defendants has violated Section 12(a)(2) of the Securities Act.

484. Plaintiffs and the Class have sustained enormous damages because the value of their Edison securities has declined precipitously.

485. Plaintiffs and the Class hereby tender their shares to the Underwriter Defendants and demand rescission.

486. At the time of their purchases, Plaintiffs and the Class were without knowledge of the wrongful conduct alleged herein, and could not have reasonably discovered those facts more than one year prior to the filing of the initial complaint in this action. The initial complaint was filed within three years of the time that the Underwriter Defendants first sold Edison securities pursuant to the Prospectus to the investing public.

COUNT III

(Violations of Section 15 of the Securities Act Against Defendants Pizarro, Rigatti, Payne, and Petmecky)

487. Plaintiffs repeat and reallege each and every allegation contained above as

if fully set forth herein, except any allegation of fraud, recklessness or intentional misconduct.

488. This claim is premised on control person liability under Section 15 of the Securities Act, and does not assert that Defendants acted with fraudulent intent.

489. Defendants Pizarro, Rigatti, Payne, and Petmecky, by virtue of their offices, directorship and/or specific acts were, at the time of the wrongs alleged herein and as set forth herein, controlling persons of SCE within the meaning of Section 15 of the Securities Act. Defendants Pizarro, Rigatti, Payne, and Petmecky, had the power and influence and exercised the same to cause SCE to engage in the acts described herein.

490. Defendants Pizarro and Rigatti, as Edison's CEO and CFO, respectively, exercised control by virtue of their positions over Edison and SCE, and exercised control by virtue of their positions over Defendants Payne and Petmecky, their subordinates.

491. Defendants Payne and Petmecky, as SCE's CEO and CFO, respectively, exercised control by virtue of their positions over SCE.

492. Defendants Pizarro, Rigatti, Payne, and Petmecky's positions made them privy to and provided them with actual knowledge of the material facts concealed from Plaintiffs and the Class.

493. By virtue of the conduct alleged herein, the Defendants Pizarro, Rigatti, Payne, and Petmecky are liable as control persons for the violations of Section 11 by the persons they controlled, as alleged in Count I.

494. None of the Defendants named in ¶489 above conducted a reasonable investigation or possessed a reasonable basis for the belief that the statements contained in the Registration Statement and identified in ¶¶346-51 above were true, were without omissions of material fact, and were not misleading.

495. Each of the Defendants named in ¶489 above is liable to Plaintiffs and the Class for damages suffered as a result of the Securities Act violations of the persons they controlled.

COUNT IV

(Violations of Section 10(b) of the Exchange Act and Rule 10b-5 Promulgated Thereunder Against the SCE Defendants)

496. Plaintiffs repeat and reallege ¶¶1 to 465 above. This claim is asserted against the SCE Defendants and is premised upon Section 10(b) of the Exchange Act, 15 U.S.C. § 78j(b), and Rule 10b-5 promulgated thereunder by the SEC.

497. During the Class Period, the SCE Defendants engaged in a plan, scheme, conspiracy and course of conduct, pursuant to which they knowingly or recklessly engaged in acts, transactions, practices and courses of business which operated as a fraud and deceit upon Plaintiffs and the other members of the Class; made various untrue statements of material facts and omitted to state material facts necessary in order to make the statements made, in light of the circumstances under which they were made, not misleading; and employed devices, schemes and artifices to defraud in connection with the purchase and sale of securities. Such scheme was intended to, and, throughout the Class Period, did: (i) deceive the investing public, including Plaintiffs and other Class members, as alleged herein; (ii) artificially inflate and maintain the market price of Edison securities; and (iii) cause Plaintiffs and other members of the Class to purchase or otherwise acquire Edison securities and options at artificially inflated prices. In furtherance of this unlawful scheme, plan and course of conduct, the SCE Defendants, and each of them, took the actions set forth herein.

498. Pursuant to the above plan, scheme, conspiracy and course of conduct, each of the SCE Defendants participated directly or indirectly in the preparation and/or issuance of the quarterly and annual reports, SEC filings, press releases and other statements and documents described above, including statements made to securities

analysts and the media that were designed to influence the market for Edison securities. Such reports, filings, releases and statements were materially false and misleading in that they failed to disclose material adverse information and misrepresented the truth about Edison finances and business prospects.

499. By virtue of their positions at Edison, the SCE Defendants had actual knowledge of the materially false and misleading statements and material omissions alleged herein and intended thereby to deceive Plaintiffs and the other members of the Class, or, in the alternative, the SCE Defendants acted with reckless disregard for the truth in that they failed or refused to ascertain and disclose such facts as would reveal the materially false and misleading nature of the statements made, although such facts were readily available to the SCE Defendants. Said acts and omissions of the SCE Defendants were committed willfully or with reckless disregard for the truth. In addition, each of the SCE Defendants knew or recklessly disregarded that material facts were being misrepresented or omitted as described above.

500. Information showing that the SCE Defendants acted knowingly or with reckless disregard for the truth is peculiarly within the Individual Defendants' knowledge and control. As the senior managers and/or directors of Edison, the Individual Defendants had knowledge of the details of Edison internal affairs.

501. The Individual Defendants are liable both directly and indirectly for the wrongs complained of herein. Because of their positions of control and authority, the Individual Defendants were able to and did, directly or indirectly, control the content of the statements of Edison. As officers and/or directors of a publicly-held Company, the Individual Defendants had a duty to disseminate timely, accurate, and truthful information with respect to Edison businesses, operations, future financial condition and future prospects. As a result of the dissemination of the aforementioned false and misleading reports, releases and public statements, the market price of Edison

securities was artificially inflated throughout the Class Period. In ignorance of the adverse facts concerning Edison business and financial condition which were concealed by the SCE Defendants, Plaintiffs and the other members of the Class purchased or otherwise acquired Edison securities at artificially inflated prices and relied upon the price of the securities, the integrity of the market for the securities and/or upon statements disseminated by the SCE Defendants, and were damaged thereby.

502. During the Class Period, Edison securities were traded on an active and efficient market. Plaintiffs and the other members of the Class, relying on the materially false and misleading statements described herein, which the SCE Defendants made, issued or caused to be disseminated, or relying upon the integrity of the market, purchased or otherwise acquired shares of Edison securities at prices artificially inflated by the SCE Defendants' wrongful conduct. Had Plaintiffs and the other members of the Class known the truth, they would not have purchased or otherwise acquired said securities, or would not have purchased or otherwise acquired them at the inflated prices that were paid. At the time of the purchases and/or acquisitions by Plaintiffs and the Class, the true value of Edison securities was substantially lower than the prices paid by Plaintiffs and the other members of the Class. The market price of Edison securities declined sharply upon public disclosure of the facts alleged herein to the injury of Plaintiffs and Class members.

503. By reason of the conduct alleged herein, the SCE Defendants knowingly or recklessly, directly or indirectly, have violated Section 10(b) of the Exchange Act and Rule 10b-5 promulgated thereunder.

504. As a direct and proximate result of the SCE Defendants' wrongful conduct, Plaintiffs and the other members of the Class suffered damages in connection with their respective purchases, acquisitions and sales of the Company's securities

during the Class Period, upon the disclosure or materialization of the risk that the Company had been disseminating misrepresentations to the investing public.

COUNT V

(Violations of Section 20(a) of the Exchange Act Against the Individual Defendants)

505. Plaintiffs repeat and reallege ¶¶1 to 465 above.

506. During the Class Period, the Individual Defendants participated in the operation and management of Edison, and conducted and participated, directly and indirectly, in the conduct of Edison business affairs. Because of their senior positions, they knew the adverse non-public information about Edison's false and misleading statements made to investors during the Class Period.

507. As officers and/or directors of a publicly owned Company, the Individual Defendants had a duty to disseminate accurate and truthful information with respect to Edison financial condition and results of operations, and to correct promptly any public statements issued by Edison which had become materially false or misleading.

508. Because of their positions of control and authority as senior officers, the Individual Defendants were able to, and did, control the contents of the various reports, press releases and public filings which Edison disseminated in the marketplace during the Class Period concerning Edison results of operations. Throughout the Class Period, the Individual Defendants exercised their power and authority to cause Edison to engage in the wrongful acts complained of herein. The Individual Defendants therefore, were "controlling persons" of Edison within the meaning of Section 20(a) of the Exchange Act. In this capacity, they participated in the unlawful conduct alleged which artificially inflated the market price of Edison securities.

509. Each of the Individual Defendants, therefore, acted as a controlling person of Edison. By reason of their senior management positions and/or being directors of Edison, each of the Individual Defendants had the power to direct the

actions of, and exercised the same to cause, Edison to engage in the unlawful acts and conduct complained of herein. Each of the Individual Defendants exercised control over the general operations of Edison and possessed the power to control the specific activities which comprise the primary violations about which Plaintiffs and the other members of the Class complain.

510. By reason of the above conduct, the Individual Defendants are liable pursuant to Section 20(a) of the Exchange Act for the violations committed by Edison.

PRAYER FOR RELIEF

WHEREFORE, Plaintiffs demand judgment against Defendants as follows:

A. Determining that the instant action may be maintained as a class action under Rule 23 of the Federal Rules of Civil Procedure, and certifying Plaintiffs as the Class representatives;

B. Requiring Defendants to pay damages sustained by Plaintiffs and the Class by reason of the acts and transactions alleged herein;

C. Awarding Plaintiffs and the other members of the Class prejudgment and post-judgment interest, as well as their reasonable attorneys' fees, expert fees and other costs; and

D. Awarding such other and further relief as this Court may deem just and proper.

DEMAND FOR TRIAL BY JURY

Plaintiffs hereby demand a trial by jury.

Dated: November 27, 2019

Respectfully submitted,

POMERANTZ LLP

/s/ Louis C. Ludwig

Patrick V. Dahlstrom (*pro hac vice*)

Louis C. Ludwig (*pro hac vice*)
10 South La Salle Street, Suite 3505
Chicago, Illinois 60603
Telephone: (312) 377-1181
Facsimile: (312) 377-1184
Email: pdahlstrom@pomlaw.com
lcludwig@pomlaw.com

POMERANTZ LLP
Jennifer Pafiti (SBN 282790)
468 North Camden Drive
Beverly Hills, CA 90210
Telephone: (818) 532-6499
E-mail: jpafiti@pomlaw.com

POMERANTZ LLP
Jeremy A. Lieberman
J. Alexander Hood II
Jonathan Lindenfeld
600 Third Avenue, 20th Floor
New York, New York 10016
Telephone: (212) 661-1100
Facsimile: (212) 661-8665
Email: jalieberman@pomlaw.com
ahood@pomlaw.com
jlindenfeld@pomlaw.com

BRONSTEIN, GEWIRTZ & GROSSMAN, LLC
Peretz Bronstein
60 East 42nd Street, Suite 4600
New York, New York 10165
Telephone: (212) 697-6484
Email: peretz@bgandg.com

Attorneys for Plaintiffs

PROOF OF SERVICE VIA ELECTRONIC POSTING PURSUANT TO CENTRAL DISTRICT OF CALIFORNIA LOCAL RULES AND ECF GENERAL ORDER NO. 10-07

I, the undersigned, say:

I am a citizen of the United States and admitted to practice before this Court, *Pro Hac Vice*. I am over the age of 18 and not a party to the within action. My business address is Pomerantz LLP, Ten South La Salle Street, Suite 3505, Chicago, Illinois 60603.

On November 27, 2019, I caused to be served the following document:

CONSOLIDATED SECOND AMENDED CLASS ACTION COMPLAINT FOR VIOLATION OF FEDERAL SECURITIES LAWS

By posting the documents to the ECF Website of the United States District Court for the Central District of California, for receipt electronically by the parties as listed on the attached Service List.

I certify under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on November 27, 2019, at Chicago, Illinois.

s/Louis C. Ludwig
Louis C. Ludwig

Exhibit A

John W Spiegel john.spiegel@mto.com, larry.polon@mto.com

Charles S Duggan charles.duggan@davispolk.com, ecf.ct.papers@davispolk.com

Neal Alan Potischman neal.potischman@davispolk.com, sce.uw.team@davispolk.com, felicia.yu@dpw.com, angela.quach@dpw.com, ecf.ct.papers@dpw.com

Jennifer Pafiti disaacson@pomlaw.com, ahood@pomlaw.com, kmsaletto@pomlaw.com, abarbosa@pomlaw.com, jpafiti@pomlaw.com

Adam C McCall amccall@zlk.com

John M Sorich john.sorich@piblaw.com, rhonda.viers@piblaw.com

Patrick V Dahlstrom pdahlstrom@pomlaw.com

Lauren Claire Barnett lauren.barnett@mto.com, gigi.ruegsegger@mto.com

Jeremy A Lieberman disaacson@pomlaw.com, jalieberman@pomlaw.com, abarbosa@pomlaw.com

Dana M Seshens dana.seshens@davispolk.com

Louis C Ludwig lcludwig@pomlaw.com

Leigh R Handelman lsmollar@pomlaw.com

Craig T Cagney craig.cagney@davispolk.com

John Michael Gildersleeve lori.cruz@mto.com, john.gildersleeve@mto.com

Mariel Alexandria G Gerlt-Ferraro laura.bremmer@piblaw.com, mariel.gerlt-ferraro@piblaw.com, julia.hernandez@piblaw.com

Adam Marc Apton aapton@zlk.com

Jordan L Lurie jllurie@pomlaw.com

EXHIBIT H

STATE OF CALIFORNIA EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

October 12, 2017

Ms. Merideth Allen
Senior Director, Regulatory Affairs
Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105

Re: Order to Preserve Evidence

Dear Ms. Allen:

This directive affirms a verbal communication between Charlotte TerKeurst, Program Manager in the Safety and Enforcement Division (SED) and you at approximately 6:00 p.m. on October 10, 2017 regarding Pacific Gas and Electric Company's (PG&E) obligation to preserve all evidence with respect to the Northern California wildfires in Napa, Sonoma, and Solano Counties.[1] In that communication, Ms. TerKeurst reminded PG&E of the need to preserve all evidence, and PG&E acknowledged that it would do so.

Pursuant to Public Utilities Code Section 316 and General Order (GO) 95, Rule 19, PG&E must preserve any factual or physical evidence under its, or its agent's, physical control, custody or possession related to the fires. This physical evidence includes all failed poles, conductors and associated equipment from each fire event. The physical evidence must be cataloged and tagged in a manner that will identify where it came from so that SED staff may reconstruct the poles for analysis. PG&E shall inform SED staff prior to moving any physical evidence from its current location to a compliant storage facility.

In addition, PG&E must inform all employees and contractors that they must preserve all electronic (including emails) and non-electronic documents related to potential causes of the fires, vegetation management, maintenance and/or tree-trimming.

[1] These fires started overnight on October 8, 2017 and include the Atlas Fire, Patrick Fire, Nuns/Norrbon Fire, Pressley Fire, Adobe Fire, Tubbs Fire and Pocket Fire.

Please contact me if you have any questions concerning this preservation order.

Sincerely,

Elizaveta Malashenko
Director
Safety and Enforcement Division

cc: President Michael Picker
Commissioner Carla Peterman
Commissioner Liane Randolph
Commissioner Cliff Rechtschaffen
Commissioner Martha Guzman Aceves

EXHIBIT I

FILED
11/30/17
04:59 PM

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Investigation Into the November 2017 Submission of Pacific Gas and Electricity Company's Risk Assessment and Mitigation Phase.	Investigation 17-11-003 (Filed November 9, 2017)

2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 M)

PETER VAN MIEGHEM

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2902
Facsimile: (415) 973-5520
E-Mail: Peter.VanMieghem@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: November 30, 2017

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Investigation Into the November 2017 Submission of Pacific Gas and Electricity Company's Risk Assessment and Mitigation Phase.	Investigation 17-11-003 (Filed November 9, 2017)

**2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT
OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 M)**

In compliance with California Public Utilities Commission (Commission or CPUC) Decisions (D.) 14-12-025 and 16-08-018, and the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E or the Company) respectfully submits its 2017 Risk Assessment Mitigation Phase (RAMP) Report (Report). Consistent with the Commission's requirements set forth in the above decisions and related proceedings, PG&E's RAMP submission precedes PG&E's 2020 General Rate Case (GRC) Application and, among other things, provides initial quantitative, probabilistic views of the Company's top safety risks; identifies the costs associated with controlling these risks; and describes future mitigation plans based on an alternatives analysis and informed by the concept of risk-spend efficiency. PG&E also has included in its RAMP filing a specific discussion on the Company's safety culture, executive engagement, and compensation practices, risk evaluation of substations, and information on steady state asset replacement for Gas Operations, Electric Operations and Power Generation.

I. BACKGROUND AND PROCEDURAL HISTORY

In Decision 14-12-025, the Commission adopted a risk-based decision-making framework (Framework) into the Rate Case Plan (RCP) for the energy utilities' GRCs. The Framework was developed as a result of Senate Bill (SB) 705 (Statutes of 2011, Chapter 522), which stated in Public Utilities Code Section 963(b)(3):

> It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.

Under Public Utilities Code Section 750, the Commission was directed to "develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation."

The Framework consists of the following, based on these directives:

> For the large energy utilities, this will take place through two new procedures, which feed into the GRC applications in which the utilities request funding for such safety-related activities. These two procedures are: (1) the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, which are to be consolidated; and (2) a subsequent Risk Assessment Mitigation Phase (RAMP) filing in an Order Instituting Investigation for the upcoming GRC wherein the large energy utility files its RAMP in the S-MAP reporting format describing how it plans to assess its risks, and to mitigate and minimize such risks. The RAMP submission, as clarified or modified in the RAMP proceeding, will then be incorporated into the large energy utility's GRC filing.[1/]

In D.16-08-018, the Commission adjudicated the consolidated S-MAP applications and the format of the RAMP submissions. In that decision, the Commission adopted guidelines for what the RAMP submissions should include, as well as an evaluation method for RAMP submissions. In addition, the Commission held that PG&E's November 30, 2017 RAMP filing shall include the Gas Transmission and Storage system.[2/]

On September 1, 2017, PG&E submitted a letter requesting an Order Initiating Investigation (OII). OII 17-11-003 was filed by the Commission on November 9, 2017.

II. RISK ASSESSMENT MITIGATION PHASE REPORT

PG&E's Report is organized in chapters, as follows:

1/ D.14-12-025 at 2-3.

2/ D.16-08-018, pp. 154-5.

CHAPTER	TITLE
22	Climate Resilience
Appendix 1	Risk Assessment For Substations
Appendix 2	Steady State Operations

PG&E has also provided supporting Workpapers to this Report.

III. CONCLUSION

The models presented in this RAMP filing are first generation probabilistic operational risk models intended to represent progress and a step forward on PG&E's path to data-driven, risk-informed decision making. PG&E has made significant progress and has evolved its approach to risk management during the development of this RAMP filing. PG&E is committed to building on the progress made through the RAMP process by incorporating lessons learned, and additional regulatory comments and insights, with the goal of minimizing risk and maximizing the safety of PG&E's customers and the communities PG&E serves.

Respectfully submitted,

PETER VAN MIEGHEM

By: *_____/s/ Peter Van Mieghem_____*
PETER VAN MIEGHEM

Pacific Gas and Electric Company
77 Beale Street. B30A
San Francisco, CA 94105
Telephone: (415) 973-2902
Facsimile: (415) 973-5520
E-Mail: Peter.VanMieghem@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: November 30, 2017

Investigation: 17-11-003
(U 39 G)
Exhibit No.:
Date: November 30, 2017
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT

TABLE OF CONTENTS

(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY

2017 RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER A

INTRODUCTION

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER A
INTRODUCTION

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) respectfully submits its first Risk Assessment and Mitigation Phase (RAMP) filing. The RAMP filing is a requirement of the California Public Utilities Commission (CPUC or Commission) General Rate Case (GRC) process, applicable to all large investor-owned utilities in the state, and is intended to provide the Commission and other stakeholders with an early indication of each utility's risk priorities and mitigation plans that have been informed by the development and application of probabilistic risk models.

This RAMP precedes PG&E's 2020 GRC Application and provides initial quantitative, probabilistic views of the Company's top 22 safety risks; identifies the costs associated with controlling these risks; and describes future mitigation plans based on an alternatives analysis and informed by the concept of risk-spend efficiency.

PG&E also has included in its RAMP filing a specific discussion on the Company's safety culture, executive engagement, and compensation practices; risk evaluation of substations; and information on steady state asset replacement for Gas Operations, Electric Operations and Power Generation.

It is important to note that the analysis and identified risks presented in this RAMP filing reflect PG&E data and modeling efforts as of November 2017. This filing evaluates the risks using best currently available data and assumptions as necessary; analyzing mitigation alternatives by understanding the potential risk reduction effectiveness of each and the associated costs—two fundamental pieces of the Risk Spend Efficiency (RSE) calculation; and making decisions about how to effectively manage the risk that will be included in the Company's 2020 GRC application.

As shown in the Gas Operations risk chapters within this filing, following the San Bruno gas pipeline explosion, extensive analysis was completed internally and by third-party experts to identify long-term actions to enhance the management of gas assets and to reduce risk. The modeling of specific risk events included in RAMP confirmed that the Company is taking the right actions and new actions are not yet needed. In Electric Operations, new insights have been gained. For example, the data used for the RAMP analysis shows that the safety consequence associated with Distribution Overhead Conductor is more often a result of people coming in contact with intact conductor, rather than resulting from wire down events. As a result, mitigations chosen in that chapter include a

focus on getting the message out to populations of people most likely to be working at heights around energized overhead conductor. PG&E believes there is value in further developing operational risk modeling techniques and using them in management-led risk and compliance committees and within the senior management-led integrated planning process to help drive better decision making and clearly demonstrate line of sight between risks, drivers, alternative mitigations and anticipated risk reduction.

PG&E continues to learn and adapt to a changing environment by refining its approach to quantitative risk assessment, applying additional sources of data, and gathering more information about the interrelationship between risks. As a result, risk models presented in this filing will improve over time and actions taken to manage risks may change.

B. Background

Managing risk is a continually evolving process, and while there are inherent risks in delivering gas and electricity to 16 million Californians, PG&E's top priority is always the safety of its customers, employees and the public. While it may not be possible to eliminate all risks such as those associated with natural disasters, wildfires and earthquakes, PG&E's goal is to proactively prepare and enhance its infrastructure to deliver safe and reliable energy every day. By systematically and comprehensively identifying, analyzing, evaluating, mitigating, and monitoring risks that could potentially prevent PG&E from achieving its goal, PG&E's Enterprise and Operational Risk Management (EORM) program enables PG&E to reduce this inherent risk.

Since 2011, when PG&E first established its EORM Program, the Company has:

- Developed and refined a comprehensive, prioritized risk register;
- Implemented a strong central governance function to provide risk management guidance and insights into the progress being made;
- Incorporated risk into the Integrated Planning process;
- Set annual goals year-over-year to improve risk quantification and improve the Company's ability to measure risk reduction; and
- Enabled visibility of risk management progress through discussion at Line of Business (LOB) Risk and Compliance Committee meetings and executive-led risk governance committees, and regular presentations to committees of the Boards of Directors of PG&E Corporation and PG&E. In these different forums, PG&E continues to evaluate any new information and determine whether or not a change in course of action is required to respond to immediate or short-term crises outside of the RAMP/GRC process and adjust as necessary. PG&E expects an explanation of measures taken to mitigate risk will occur annually in accordance with accountability reporting, once

requirements are established through the S-MAP process. This report will also contain a description of any changes to previously stated mitigation plans.

In the interests of providing safe and reliable energy to all our customers and communities, PG&E continues to evolve its risk management process to better understand the sources of risk and identify the best possible opportunities for further reducing them. This has involved developing probabilistic operational risk models that enable the Company to: (1) describe risks as events with a distribution of outcomes, rather than a point estimate, (2) quantitatively evaluate alternative mitigation strategies and estimate risk reduction, (3) choose implementable risk mitigations informed by RSE, and (4) better monitor top risks.

C. PG&E's Approach

In its approach to the RAMP and in the filing itself, PG&E has taken great care to be transparent, accountable and inclusive. In doing so, parties have been able to see how PG&E has modeled each of its top safety risks and offer ideas and feedback on how its approach may be refined or improved.

The Company has demonstrated transparency by documenting its modeling assumptions and rationale for decisions in a manner that the Company believes is repeatable, straightforward and understandable.

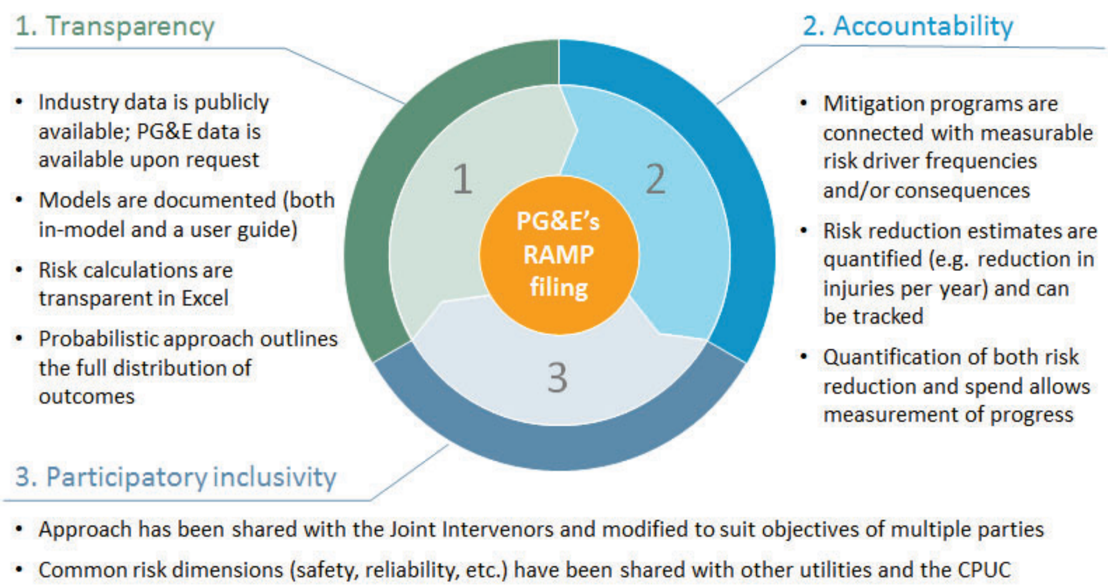
Risk chapters and supporting workpapers include data that will provide the basis for accountability reporting such as risk driver frequencies and metrics. This can help PG&E demonstrate where the Company has met its risk reduction goals, and provide a basis to explain any variance from forecast.

In the spirit of participatory inclusivity, PG&E has reached out and met with interested parties, sharing assumptions, modeling approaches, and lessons learned with the goal of delivering a RAMP filing that reflects comments and feedback provided throughout the process. Beginning in November 2016, PG&E has met with various stakeholders including the CPUC SED, CPUC Office of Ratepayer Advocates (ORA), CPUC Office of Safety Advocates (OSA), Coalition of California Utility Employees (CUE), The Utility Reform Network (TURN) and Indicated Shippers (IS) among other to share how PG&E is preparing for RAMP, the assumptions the Company is making, and what is being learned. PG&E has shared the list of top safety risks and the methodology used to identify them; the general modelling and approach assumptions being considered and used; how the probabilistic operational risk models were being constructed; the approach to identifying and using data sources; any identified limitations; and next steps.

All parties asked questions and provided feedback that was incorporated as appropriate.

Figure A-1 provides some specific takeaways from the efforts undertaken over the past year to deliver on the objectives of RAMP.

Figure A-1: PG&E's RAMP Filing Approach



In addition to being transparent, accountable, and inclusive, PG&E's RAMP approach is also based on achieving seven main objectives:

1. **Focus on Safety**

   This RAMP filing includes a probabilistic assessment of the Company's top safety risks including a description of the controls currently in place, mitigations underway, and plans for improving the mitigation of each risk, including two alternatives. It also includes chapters dedicated to describing PG&E's safety culture, executive engagement and compensation policies.

2. **Move Towards Probabilistic Calculations as Much as Possible**

   PG&E developed individual and comparable risk models for each of the identified top safety risks. The risk models are meant to help PG&E LOBs understand, from a quantitative perspective, the frequencies associated with risk drivers and the range of consequences associated with each risk event. The RAMP operational risk models produce full risk distributions (where a tail average, expected value, or any point on the curve can be measured) based

on PG&E-specific data whenever feasible, industry data where applicable, calibrated subject matter expertise, and combinations thereof. A description of the data sources used to assess each risk is discussed in the individual risk chapters of this filing and in associated workpapers.

3. Present Two Alternative Mitigation Plans for Each Risk

All the risks included in PG&E's RAMP filing are presented in their own chapter, in the same manner, using the same framework that, in each chapter, culminates in an alternatives analysis showing the proposed mitigation plan and two alternative plans. The information included in each risk-specific chapter addresses the first eight of the ten steps in the Cycla 10-step Risk-informed Resource Allocation Process with the final two steps to be addressed later.[1] Each risk chapter includes the following:

- An executive summary that includes the risk name, scope of the risk, the data sources used, and a brief discussion of PG&E's experience in managing the risk;
- A risk assessment based on a bow tie assessment framework, including a data-driven evaluation of the risk exposure, risk drivers and frequencies, and the range of consequences associated with the risk resulting in a Multi-Attribute Risk Score (MARS)[2] [Cycla Step 1: Identify Threats; Cycla Step 2: Characterize Sources of Risk];
- Current controls and mitigations underway through 2019;[3]
- A proposed plan to mitigate the risk, which identifies a mitigation strategy informed by an early stage RSE calculation to be included, or adjusted as necessary, in the 2020 GRC and an alternatives analysis [Cycla Step 3: Mitigation Identification; Cycla Step 4: Evaluate the Anticipated Risk Reduction; Cycla Step 5: Determine Resource Requirements; Cycla Step 6: Mitigation Selection; Cycla Step 7: Identify

---

1 The RAMP filing addresses the first eight of the 10 Cycla Steps for Risk-informed Resource Allocation. The two steps this process does not address Step 9: Adjusting mitigations following CPUC decision on allowed resources and Step 10: Monitoring the effectiveness of risk mitigations will be addressed after receiving the GRC decision and in the submission of the Accountability Report, respectively.

2 Reference Section 1.9 – Multi-Attribute Risk Score (MARS) in Chapter B for explanation of the MARS calculation and methodology.

3 Controls are limited to work completed and in place in 2016. Mitigations are listed in this filing in two sections: (1) work to be completed in the 2017-2019 timeframe; and (2) work to be completed in the 2020-2022 timeframe. The first section of mitigations was reflected in the 2017 GRC (unless otherwise stated) and the second section of mitigations will be included in the 2020 GRC (again, unless otherwise stated).

Total Cost; and Cycla Step 8: Adjust Mitigations Considering Resource Constraints];

- Proposed metrics for evaluating risk reduction effectiveness; and
- A summary of next steps.

4. **Present an Early State "Risk Mitigated to Cost Ratio" or Related "Risk Reduction Per Dollar Spent"**

The outputs of the risk assessments, i.e., the baseline MARS evaluation and RSE calculations for each mitigation, are presented to show the potential for comparing risks and proposed mitigations.

It is important to note that given this is PG&E's first attempt at developing probabilistic risk models for its top safety risks (beyond what is done under the purview of the Nuclear Regulatory Commission for PG&E's Diablo Canyon Power Plant (DCPP) operations)[4] improvements in the quality and availability of data and a deeper understanding of risk tolerance are needed before risks and the effectiveness of mitigations truly can be compared. However, using the RSE metric based on a consistently calculated MARS is a first step towards comparability across risks and mitigations.

5. **Describe the Company's Safety Culture, Executive Engagement, and Compensation Policies**

The safety culture chapter describes PG&E's plan to improve safety culture over time and includes descriptions about executive engagement in the process. Included in a separate chapter,[5] PG&E has described how its compensation policies align with promoting safety as a key objective of the Company.

6. **Identify Lessons Learned**

PG&E describes lessons learned and next steps throughout this filing. In addition to programmatic lessons learned about quantitative operational risk modeling[6] and alternatives analysis that are included in next steps, each

---

4 PG&E's DCPP Nuclear Operations team has an established Probabilistic Risk Assessment (PRA) model developed and refined over the past two plus decades. The DCPP PRA model is regularly used by the plant for decision-making.

5 Chapter D, Compensation Policies Relating to Safety.

6 For example, as described in Chapter B, PG&E has found that the trust attribute—which is difficult to obtain meaningful data for – may have limited value in assessing safety-related risks.

individual risk chapter includes a similar discussion about how to improve the models that have been developed.

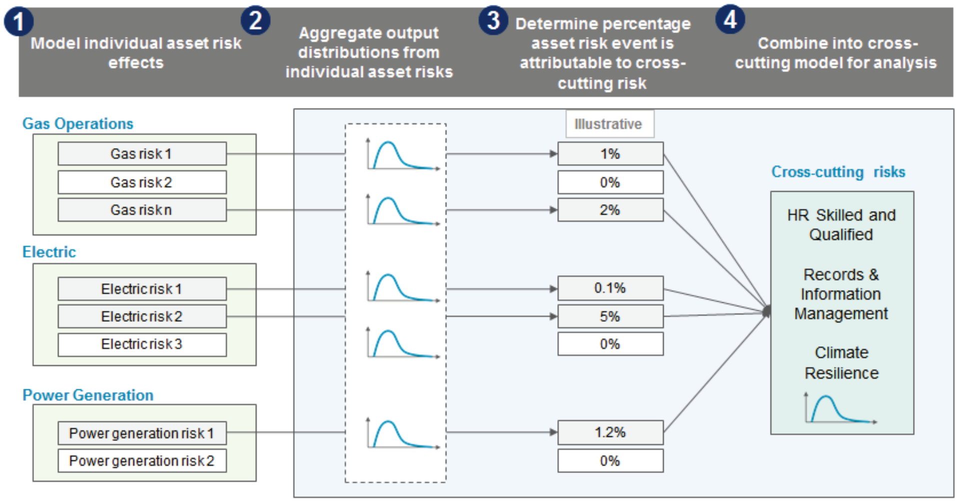
One of the main lessons learned in this process is with respect to cross cutting risks. Three of PG&E's top safety risks presented in this filing—Records and Information Management, Skilled and Qualified Workforce, and Climate Resilience—are interrelated and can be considered sub drivers of other risks. For example, the Skilled and Qualified Workforce risk, i.e., not having a skilled and qualified workforce to correctly perform work, could have significant safety consequences and is considered by PG&E a risk in and of itself. Additionally, the lack of a skilled and qualified workforce also can cause "incorrect work operations" which is an identified risk driver for a number of risks such as the Gas Transmission Pipeline Failure with Ignition risk.

To address this, PG&E developed a cross-cutting model that is dependent on the outputs from other asset or stand-alone risk models. These models are not specific risk events; instead, they are an aggregation of the associated stand-alone or asset risks.

The three cross-cutting risk models are Records and Information Management, Skilled and Qualified Workforce, and Climate Resilience. Records and Information Management and Skilled and Qualified Workforce evaluate each of the stand-alone risks and estimate what portion of the risk could be attributed to a records issue or a skilled and qualified workforce issue, respectively. The portion attributed to these two cross-cutting risks is an input to the appropriate cross-cutting model. A slightly different approach is taken for Climate Resilience. The Climate Resilience model anticipates that climate change may increase some of the stand-alone risks. For example, stronger and more frequent storms could lead to additional Distribution Overhead Conductor Primary risk as more wires may be downed as a result. These inputs are anticipated in the output of the Climate Resilience model.

Figure A-2 shows a graphical representation of the approach taken to model cross-cutting risks.

Figure A-2: Cross-Cutting Risk Model Methodology



7. Prepare for Annual Accountability Reports

This filing includes information that may be used in future accountability reports, including metrics and forecasted risk reduction. PG&E expects more work will be done with the SED-sponsored Metrics Working Committee to solidify what accountability reporting will ultimately include and will participate in that process.

D. Choosing the Top Safety Risks for Inclusion in RAMP

PG&E started the RAMP process with the Company's Risk Register that contains over 200 risks. To populate this risk register with the most important risks to the Company, LOBs hold workshops and brainstorming sessions to identify "worst case probable events" (loosely described as "P95" events) that could prevent PG&E from achieving its objective of providing safe, reliable, affordable and clean energy to our customers every day. These risk events are evaluated using a standard risk evaluation tool (RET) and rank ordered on a relative basis based on a risk score. This list of risks becomes the Company Risk Register.

The RET is a 7x7 matrix consisting of seven consequence levels that range from negligible to catastrophic across six weighted attribute areas and seven frequency levels that range from once every 100+ years to >10 times/year.

When assessing identified risks, LOBs choose the appropriate consequence level (1-7) for each of the six weighted consequence attributes based on how the risk is described and then assign the frequency level (1-7) by which those consequences might occur.

Next, an algorithm is applied using consequence and frequency "inputs" to establish the risk score ("output").

The weighting of the consequence attributes in the algorithm is designed such that safety risks score higher than financial or reliability risks. Also, the consequences are weighted more heavily than frequency in the overall score. As a result, this approach tends to prioritize high consequence, low frequency safety risks.

The top risks are then flagged for senior management attention and oversight and are prioritized for assessing additional risk reduction options. In addition, any risk that is assessed as having a potentially catastrophic impact, regardless of frequency, is designated as an Enterprise Risk and is currently overseen by PG&E's Board of Directors.

PG&E evaluated several options for determining which risks to include in its RAMP filing and reviewed these options with internal and external stakeholders.[7] Based on stakeholder feedback, PG&E included the highest scoring risks that had a potential safety consequence of causing permanent or serious injuries or illnesses to employees, the public or to contractors. This captured the 22 top risks noted in Table A-1 below.

---

7 External stakeholders included Sempra, CPUC SED, ORA, OSA, TURN, IS and Energy Producers and Users Coalition, and CUE.

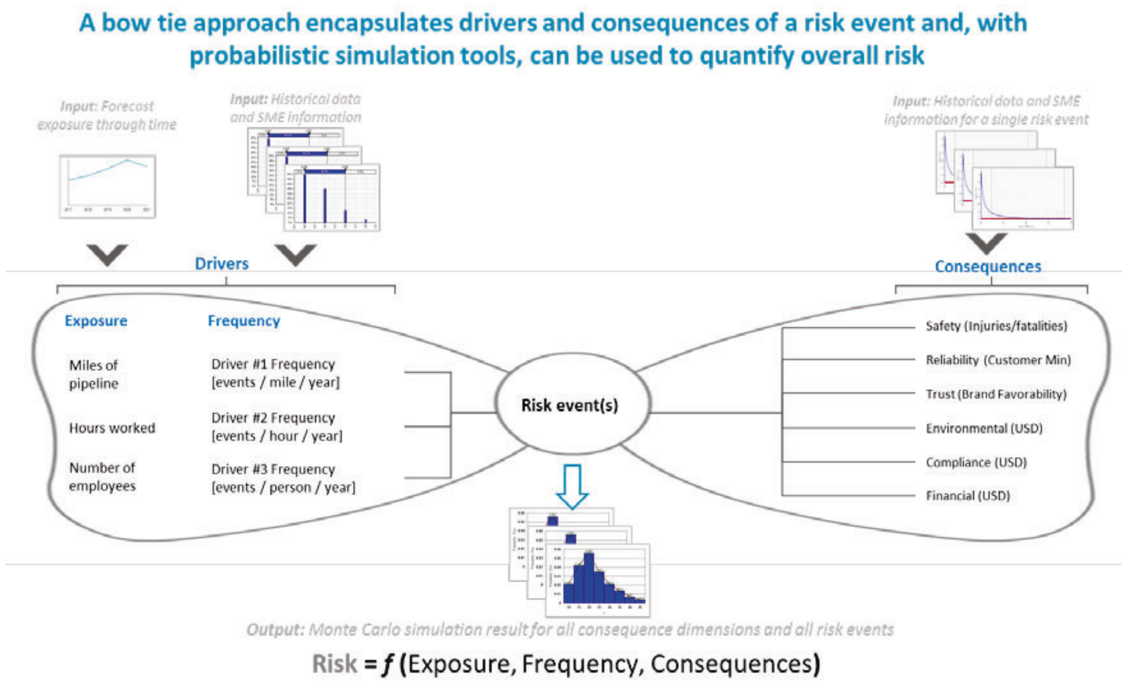
Table A-1: PG&E RAMP Risks

Chapter	Name	LOB
1	Transmission Pipeline Failure – Rupture with Ignition	Gas Operations
2	Failure to Maintain Capacity for System Demands	Gas Operations
3	Measurement and Control Failure – Release of Gas with Ignition Downstream	Gas Operations
4	Measurement and Control Failure – Release of Gas with Ignition at M&C Facility	Gas Operations
5	Release of Gas with Ignition on Distribution Facilities – Cross Bore	Gas Operations
6	Compression and Processing Failure – Release of Gas with Ignition at Manned Processing Facility	Gas Operations
7	Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore	Gas Operations
8	Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility	Gas Operations
9	Distribution Overhead Conductor – Primary	Electric Operations
10	Transmission Overhead Conductor	Electric Operations
11	Wildfire	Electric Operations
12	Nuclear Operations and Safety – Core Damaging Event	Generation
13	Hydro System Safety – Dams	Generation
14	Contractor Safety	Safety and Health
15	Employee Safety	Safety and Health
16	Motor Vehicle Safety	Safety and Health
17	Lack of Fitness for Duty Awareness	Safety and Health
18	Cyber Attack	Information Technology
19	Insider Threat	Information Technology
20	Records and Information Management	Enterprise Records and Information Management
21	Skilled and Qualified Workforce	Human Resources
22	Climate Resilience	Strategy and Policy

E. Risk Assessment and Model Overview

Through the RAMP process, PG&E has developed 22 first generation probabilistic operational risk models based on the bow tie analysis framework illustrated in Figure A-3 below.

Figure A-3: Illustrative Bow Tie Analysis Framework



A bow tie analysis is constructed using four basic components:

1. **The Risk Event:** The center of the bow tie. The risk is an event or events that PG&E seeks to avoid and could impact PG&E's ability to deliver on its objective of providing safe, reliable, affordable, and clean energy.
2. **The Exposure:** The far left side of the bow tie. Exposure is the measure that fundamentally determines the physical materiality of the risk, e.g., miles of transmission pipeline, number of employees, miles of overhead distribution lines, etc. Exposure is important for defining the scope, context and granularity of the risk, i.e., is the risk associated with the entire system, or focused on one piece of it?
3. **The Risk Drivers:** To the immediate left of the center of the bow tie. Risk drivers are the factors that could cause one or more risk events to occur. The bow tie uses actual data (PG&E data, industry data, or calibrated subject matter expertise, or some combination thereof), to measure the frequencies associated with each risk driver. These frequencies are reported as number of risk events caused by that risk driver, per unit of exposure, per unit of time, e.g., number of pipeline transmission failures with ignition events/miles of transmission pipeline/year caused by external corrosion. This level of

detail enables PG&E to focus attention on the most important risk drivers. Risk driver frequency data, combined with exposure, enables PG&E to compare its performance against industry performance to begin to understand what may be driving any differences.

4. **The Consequences:** The right side of the bow tie. Consequences are the range of outcomes associated with the risk occurrence. In PG&E's risk framework, consequences are measured across six attributes: (1) Safety-separated into injuries and fatalities; (2) Environmental; (3) Compliance; (4) Reliability; (5) Trust; and (6) Financial (excluding below the line, shareholder costs). Continuing with the Gas Transmission Pipeline Failure with Ignition example, the consequences depend largely on where the event occurs. If the risk occurs in a heavily populated area, the consequences are more likely to be severe than consequences resulting from the same event occurring in a remote area. The consequence data is then used in Monte Carlo simulations to develop a full distribution of risk consequences to understand the probability associated with each consequence attribute.

A more detailed description of PG&E's approach to probabilistic risk modeling, for stand-alone and cross-cutting risk models is included in Chapter B – Risk Model Overview.

F. Expected Value and Tail Average

PG&E's EORM Program considers the possibility of low frequency, high consequence events, even if they have never occurred in the Company's history. As such, in modeling our top safety risks, PG&E has included the Tail Average (TA), i.e., the average of the worst 10 percent of simulated outcomes, to ensure that PG&E considers these low frequency/high consequence events and that the Company maintains the level of visibility and oversight needed to appropriately manage these types of risks.

The Expected Value (EV), or the "average" event, also is a useful measure for ensuring the Company is focused on choosing mitigations and targeting controls in the most efficient manner possible, i.e., mitigations that reduce risk across the distribution of possible outcomes, not just the TA.

By measuring both EV and TA, PG&E examines the potential impact of mitigations across the distribution of risk and can focus on mitigations that affect "extreme" events (TA) and "everyday" (EV) events.

G. Controls, Mitigations, and Risk Spend Efficiency

Control is defined as:

> *"A currently established measure that is modifying risk";*

and mitigation is defined as:

"A measure or activity proposed or in process that is designed to reduce the impact/consequences and/or the likelihood/probability of an event."

PG&E has identified existing controls and mitigations for each top safety risk to understand the current level of risk and use this understanding to inform the 2020-2022 mitigation plans. The frequencies of the risk drivers and the distributions of the associated consequence attributes reflect available data through 2016. For purposes of RSE calculations, PG&E focused on mitigations (rather than controls) due to the forward looking nature of its program and the desire to understand the potential risk reduction associated with new mitigation investments. In some cases, mitigations included in the RAMP risk chapters are new items and in other cases, mitigations represent a strengthening of existing controls.

Mitigations proposed in each chapter are designed either to reduce one or more of the risk driver frequencies or modify the consequence outcomes of one or more attributes. The connection between the mitigation and the risk driver(s) or consequence attribute(s) each mitigation addresses is illustrated in table format within each risk specific chapter.

PG&E did not estimate RSE for controls and existing mitigations that end prior to 2020. Controls already funded through the regulatory process are often associated with work necessary for compliance and have been subject to regulatory review in prior rate cases. PG&E instead focused on calculating RSEs for all proposed mitigations for items to be included in the 2020 GRC over the years 2020-2022.

In this filing, individual mitigations are "bundled" together to create mitigation plans. Each mitigation plan may include both mitigations (risk reducing activities) and "foundational" activities. Foundational activities can be thought of as initial work needed to implement future mitigations, e.g., investments in Information Technology (IT) infrastructure or data gathering. Foundational activities generally do not result in risk reduction and therefore do not have associated RSE calculations. RSEs for the entire mitigation plan are calculated as follows:

$$RSE_{Mitigation\ Plan} = \frac{Risk\ Reduction_{Mitigation\ 1} + \dots + Risk\ Reduction_{Mitigation\ n}}{Total\ Cost\ of\ All\ Mitigations\ in\ the\ Plan}$$

The RSEs presented in the alternatives analysis section of each chapter are based on costs and risk reduction forecasted over the 2017-2022 timeframe. This methodology was shared during stakeholder meetings and there was general

agreement that it was unrealistic to use first generation models, populated with first generation data, to predict the risk reduction achieved in the 2017 GRC period (2017-2019), then re-baseline and predict again what risk reduction would be achieved over the 2020 GRC period (2020-2022).

PG&E approached the concept of RSE as a way to evaluate risk mitigation plans as one of many inputs into the overall decision making process; however, it does not always dictate a particular result. In some cases, work that has low or no RSE will be selected above mitigations with high RSE. These cases generally fall into four categories:

1. **Some risks may require foundational work before risk reducing work can begin.** IT infrastructure is a good example of this type of risk. The investment in IT infrastructure (e.g., servers, operating systems, databases, etc.) may not directly reduce risk and would naturally receive a "0" RSE score. But without that investment, PG&E may not be able to efficiently manage risk in the future.
2. **Some risks may have little or no associated data.** Data may not be readily available; it may be insufficient or not collected at all. Risk reduction from given activities may not be measurable or observable. Cyber Attack and Insider Threat are two such risks where lack of event data has made performing RSE calculations infeasible at this time.
3. **Risks where the long term benefit of the project outweighs the shorter term costs.** PG&E's probabilistic risk model is a 6-year model that spans 2017-2022. Risk benefits that extend beyond the 2020 GRC time horizon are not captured; therefore, some capital projects where costs tend to be higher will receive a lower RSE (higher cost and equal or less risk reduction) than operations and maintenance-type expense projects because the benefits are truncated at the six year mark. Over the longer term, these capital cost intensive mitigations may prove to have better RSEs than their expense alternatives.
4. **Other constraints.** In some cases, the best RSE mitigation may not be executable for any number of reasons including feasibility, qualified workforce availability, materials availability, permitting constraints, etc.

Additionally, because RSE is a ratio, high cost mitigations with large associated risk reduction may have the same RSE as low cost mitigations with small associated risk reduction and the current risk level may warrant greater spend to achieve greater risk reduction.

Due to all of these factors, each of the risk mitigation plans includes a justification for the chosen alternative and additional justification is provided when the decision is not based on RSE alone.

H. Estimating Costs

In this filing, PG&E has presented both capital and expense recorded costs associated with risk controls and mitigations for 2016. PG&E also identifies mitigations for 2017-2019 and mitigations anticipated to be requested in the 2020 GRC, the 2019 Gas Transmission and Storage (GT&S) Rate Case, and future Transmission Owner rate cases under Federal Energy Regulatory Commission jurisdiction.

PG&E made a number of assumptions in estimating costs as follows:

1. Costs are reported in ranges due to the uncertainty associated with predicting future mitigation needs. Gas Operations provided point estimates for alignment with the 2019 GT&S Rate Case forecast. PG&E has used the best available information when calculating and estimating the costs associated with each mitigation. Because PG&E's GRC forecasting process is still in the early stages, however, the mitigation cost forecasts included in the 2020 GRC application may be significantly different from the estimates included in this filing.
2. Some risks are mitigated using labor not typically associated with planning orders or major work categories. PG&E has estimated costs based on the number of associated Full Time Equivalent hours multiplied by the standard employee rate for the specific job function.
3. Some mitigations have a risk reduction benefit across multiple risks. PG&E has made a best effort to estimate cost allocations between risks where feasible. Where this allocation cannot be reasonably estimated, PG&E will apply the full cost of the mitigation to each applicable risk. PG&E will not "double count" these costs in its GRC application or in any other rate case.
4. Some Below the Line (BTL) costs may be difficult to predict. PG&E removed cost types defined in its BTL Standard when analyzing financial consequences associated with risk events included in this filing.

II. Lessons Learned and Next Steps for PG&E

A. Risk Assessment

1. **Quantitative Operational Risk Modeling.** Since early 2017, PG&E began transitioning from its historical qualitative approach to a more probabilistic and quantitative approach, consistent with the expectations for this filing. Parallel to the development of its RAMP filing, PG&E has participated in Commission-led Safety Model Assessment Proceeding (S-MAP) workshops whereby intervenors and the large California IOUs shared risk assessment methodologies and explored ways to improve utility risk modeling approaches. PG&E has adopted much of what was learned during these workshops to inform the probabilistic models presented in this RAMP.

As PG&E implements this more sophisticated approach to risk assessment, data quality and availability is improved across all risks, and risk reducing activities are implemented, PG&E expects risk scores and priorities to change over time.

The Company sees value in the potential of probabilistic operational risk modeling, not only for deepening its understanding of risks but for enabling data-driven, risk-informed decision making. This quantitative approach can also support to transparent discussions about risk, mitigation strategies, and levels of risk.

This transition will involve the development of new skills, techniques and data sources. It will take time and resources to complete this transition; however, PG&E believes it can make meaningful progress toward achieving its stated goal of quantifying its top risks by 2020, while continuing to improve and evolve the operational risk models developed as part of the RAMP process.

2. **Governance, Oversight, and Evolution.** RAMP has accelerated PG&E's progress in its risk management journey towards quantifying its top risks. Today, the Company has 22 probabilistic risk models for its top safety risks and defined plans for evolving and improving these models so that even better decision making capabilities can be developed. As mentioned above, PG&E needs to better understand longer term risk reduction potential beyond the 6-year time horizon and refine its operational risk models to accommodate this type of analysis.

   PG&E has started creating a governance structure for the management and development of these and other risk models and data so they can increasingly be used in decision making. PG&E is also working on warehousing inputs and outputs; model validation and acceptance; and the development of additional analytical tools for making decisions within programs to further enhance its ability to identify, model and manage risk.

3. **Risk Tolerance.** Providing gas and electric service is an inherently risky endeavor and risk cannot be completely eliminated. Greater measurement and transparency allows the Company to discuss current levels of risk and contemplate new mitigations. Understanding risks at a more detailed level provides opportunities for the Company and its stakeholders to attempt to define a risk tolerance that can further guide investments in risk mitigation.

4. **Interrelationships between risks.** As PG&E continues to refine its approach to risk modeling, improvements will be made in identifying and understanding how risks interrelate. A more granular understanding of risk drivers obtained through fault tree/event tree analysis, for example, may enable PG&E to better understand how different failure modes interact with

one another to cause a risk event to occur. This may provide additional insights into effective mitigation options for managing risk.

B. Tracking of Associated Financials

Previously, PG&E's accounting system (SAP) was set up to track costs by major work category, work orders and planning orders, but not necessarily in the context of how those activities relate to risks on the risk register. The company has made adjustments to SAP to incorporate RAMP related IDs to track mitigation costs for use in future accountability reporting.

C. Limitations

The completeness and availability of relevant data is a challenge. To compensate for lack of data, additional assumptions, subject matter expertise and proxy data were used and referenced in work papers. Therefore, the inputs and outputs of the models may not completely mirror PG&E's experience.

PG&E does not currently optimize investments across risks. The data is not robust enough, nor are the risks comparable enough to do this effectively. Additionally, optimization is best done in the context of risk tolerance, which has yet to be defined.

III. Conclusion

The models presented in this RAMP filing are first generation probabilistic operational risk models intended to represent progress and a step forward on PG&E's path to data-driven, risk-informed decision making.

The bow tie analysis foundational to PG&E's risk assessment approach allows the Company to better see the connections between risk drivers, controls and mitigations. By using this analysis to predict the impact mitigations may have in reducing risk and understanding the effectiveness of existing controls, PG&E is able to communicate what the Company is doing to manage safety risks inherent in the business.

PG&E has made significant progress and has evolved its approach to EORM during the development of this RAMP filing. PG&E is committed to building on the progress made through the RAMP process by incorporating lessons learned, and additional regulatory comments and insights, with the goal of minimizing risk and maximizing the safety of our customers and the communities we serve.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 10
TRANSMISSION OVERHEAD CONDUCTOR (TOHC)

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 10
TRANSMISSION OVERHEAD CONDUCTOR (TOHC)

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Transmission Overhead Conductor (TOHC)
IN SCOPE	Public contact with energized intact overhead transmission conductor and TOHC wire down.
OUT OF SCOPE	Wildfires caused by wire down events.[1] Employee or contractor contact with overhead transmission conductor.[2]
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data, and subject matter expert (SME) input

Pacific Gas and Electric Company's (PG&E or the Company) Electric Operations (EO) department has been reviewing the TOHC risk since the creation of the risk register in early 2013. Overhead transmission lines are energized at high voltages, are exposed to the public, and form the backbone of PG&E's electrical system. Because of these attributes, there are inherent risks associated with overhead transmission conductors. Contact with these conductors could result in injuries and fatalities from shock and electrocution, and failure of these conductors could result in large outages or system instability. This risk continues to be a top priority for PG&E, as demonstrated through on-going investments in conductor replacement, compliance, and public safety programs.

This filing has been prepared and submitted against the backdrop of catastrophic wildfires that occurred in PG&E's service area beginning on October 8, 2017. Numerous investigations are underway. Depending on the results of those investigations, there could be an impact on PG&E's future transmission and distribution risk management approaches. PG&E has prepared this filing prior completion of the investigations as to the causes of any of the recent wildfires. The filing needs to be considered in this context. As with all risks in this filing, as more information becomes available, PG&E will make any updates to this analysis, modeling and proposing mitigations that might become appropriate.

Given this backdrop, it is important to note that the scope of this risk analysis specifically excludes Wildfire, but TOHC is included as a risk driver to the Wildfire risk

1 Refer to Risk Chapter 11 – Wildfire.

2 Refer to Risk Chapter 14 – Contractor Safety and Risk Chapter 15 – Employee Safety.

analysis.[3] The wildfire-related impacts that may be caused by TOHC assets are addressed in the Wildfire chapter, and not here, to avoid duplication.

To better understand this risk, in 2017, through the Risk Assessment and Mitigation Phase (RAMP) process, PG&E's EO department developed a probabilistic model to quantify the TOHC risk. The inputs into the TOHC risk model were developed using a bow tie risk assessment and incorporated a combination of PG&E-specific data, industry data, and SME judgement. The TOHC risk model was used to gain a better understanding of the risk drivers associated with the risk, the range of consequences, and where to target new mitigations.

As a result of the assessment, PG&E identified two main events associated with the risk: (1) third-party contact with intact conductor (either directly or via an object) and (2) third-party contact with wire down.

The assessment confirms that this risk is primarily a reliability risk rather than a safety risk based on the risk events examined in the TOHC model. PG&E has approximately 18,000 circuit miles of overhead transmission line. Using PG&E collected data, from 2012 through 2016, there have been an average 0.6 third-party injuries and 0.6 third-party fatalities a year, due to contact with overhead transmission conductor. The fatalities were caused by the unauthorized climbing of PG&E structures, an external event that is difficult for PG&E to control given the scope of its overhead transmission system. In that same time period, there has been an average of 55.8 PG&E transmission overhead wire down events per year, none resulting in injuries or fatalities. The highest frequency drivers that cause wire down events are vegetation, third-party actions (such as vehicle collisions with PG&E assets), and conductor failures due to factors such as equipment deterioration.

Through the risk assessment process, PG&E objectively evaluated its ability to reduce the TOHC risk at a reasonable cost. This risk quantification brought greater visibility to actual system exposure and drove PG&E to better quantify effectiveness of risk mitigations. To reduce TOHC risk, PG&E will implement a mitigation plan that consists of four mitigations: (1) Additional Public Awareness Outreach; (2) Additional Right of Way Expansion; (3) Additional Overhead Conductor Replacement; and (4) Additional Insulator Replacement. These mitigations address some of the largest drivers to wire down, including Vegetation and Equipment Failure – Conductor, and align with PG&E's overall asset lifecycle management objectives, where PG&E proactively replaces equipment that is approaching the end of its useful life.

---

3 The "Equipment Failure – Conductor" risk driver included in the Wildfire risk analysis includes wildfires initiated by TOHCs and distribution overhead conductors.

Areas for continued model development and risk quantification include potential refinement of the assumptions used to model the efficacy of the mitigations included in the model. Refinement may include increasing the granularity of the modeled mitigations, including mitigation benefits beyond the current RAMP timeframe, and factoring in benefits from the mitigations outside of the specific TOHC risk events. Another opportunity for improvement involves modeling the increase in risk with time due to degradation of asset health as legacy equipment reaches the end of its useful life. This forward looking approach would enable effective quantification of steady state controls and identify opportunities to increase or decrease asset lifecycle replacement to manage risk within a given tolerance.

II. Risk Assessment

A. Background

Overhead transmission lines are energized at high voltages, are exposed to the public, and form the backbone of PG&E's electrical system. Because of these properties, overhead transmission conductors have inherent risk. Contact with these conductors could result in injuries and fatalities, and failure of these conductors could result in large outages or system instability.

To help manage this risk, PG&E's EO department has been reviewing the risk since the creation of the risk register in early 2013. PG&E's assessment of the risk has evolved since that time, and PG&E currently assesses two potential events associated with the risk: third-party contact with intact conductor and third-party contact with wire down.

In a third-party contact with intact conductor event, a member of the public makes contact with a conductor that has not failed. Generally, on the transmission system, this involves contact with conductor through unauthorized climbing of PG&E structures or work occurring near the conductor.

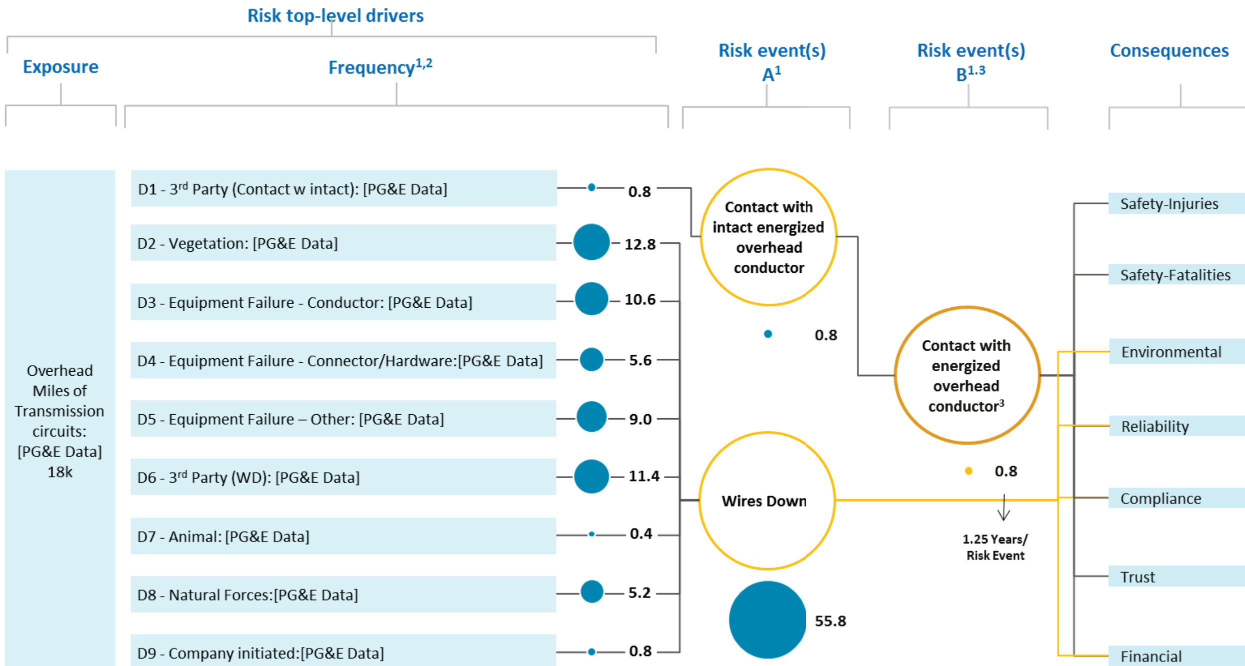
In a wire down event, a conductor falls to the ground. Wires could fail due to several drivers, including vegetation falling onto lines, equipment failure, and third-party vehicle collisions with support structures and conductors. Wire down events do not generally result in safety incidents because the transmission system has stringent system protections which de-energize lines relatively quickly. High voltage faults are more easily detected by the protection system, and transmission lines are generally located in less populated areas. All of these factors tend to reduce the safety issues associated with wire down events.

The events examined in this risk may also result in wildfire. Because wildfire is a risk with several drivers, including drivers that are not included in the TOHC risk, the wildfire

related risks of TOHC assets are described separately in detail in the Wildfire risk chapter.

This chapter discusses the inputs to and outputs of PG&E's quantitative model for the TOHC risk. It outlines the risk exposure, drivers, and consequences, and discusses current controls in place that manage this risk, as well as mitigations PG&E plans to implement to reduce this risk.

Figure 10-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.
[3]100% of D1 and 0% of D2-D9 may potentially remain energized.

B. **Exposure**

This risk is modeled using 18,352 circuit miles of TOHC as an exposure input, which is expected to remain relatively constant throughout the time horizon addressed by this filing. Circuit miles of TOHC have not materially changed since 2012 and there are no projects, developments, or expansions underway or planned that would change this exposure to any significant degree.

The circuit mileage data is sourced from historical end-of-year overhead line mileage reports extracted from PG&E's Electric Transmission Geographic Information System.[4]

4 The circuit mileage for this model includes idle line circuit miles. Idle transmission lines may remain energized at a designated voltage to help locate faults, which is important in the event those lines.

Risk exposure is not evenly distributed across PG&E's transmission overhead system. Some lines have a higher risk of failure than others. For example, lines have a higher likelihood of wire down when built near dense vegetation or when constructed in areas that experience more extreme weather. Due to this geographic and environmental diversity, the risk profile for PG&E's transmission overhead system is quite asymmetric resulting in a small fraction of PG&E's transmission overhead system representing a majority of the system risk exposure. As such, mitigations targeted in these higher risk areas have a greater impact in reducing risk. Where possible, PG&E has factored increased risk reduction from targeted work into its mitigation efficacy assumptions.

C. **Drivers and Associated Frequency**

Similar to Distribution Overhead Conductor Primary (DOCP) risk, PG&E divides the drivers of this risk into two sets based on the two risk events examined in this risk. The first set is related to the public contact with energized intact overhead conductor risk event. For the purpose of modeling this risk, contact with intact events were grouped as a single driver:

- **D1 – 3rd Party (Contact with intact)**. Third-party contact with intact conductor. This driver represents public contact with intact transmission conductor where there were fatalities or injuries, requiring in-patient hospitalization. The frequency of this driver is based on the public injury and fatality data that PG&E reports to the California Public Utilities Commission (CPUC). In the TOHC risk model, PG&E used data from the years 2012-2016. These years were selected to be consistent with the data available for the wire down drivers described below. The information is sourced from PG&E's electric incident reporting database. Between 2012 and 2016, there were four third-party events involving contact with intact conductor that resulted in injury or fatality, or an average of 0.8 events per year. Three of those events resulted in a single fatality each (or 0.6 fatalities per year), and one resulted in injuries to three people (or 0.6 injuries per year).

  The second set of drivers is related to the TOHC wire down risk event. The drivers to this event include the different causes that lead to wire down. The frequencies of these drivers are based on data that has been collected on PG&E transmission wire down events between 2012 (when PG&E first began collecting this data) and 2016. The data is comprised of information which includes the cause of each wire down event and the impact of any resulting outage.

  For wire down events, the TOHC risk model assumes that transmission overhead wires do not remain energized when there is a wire down event. This assumption is based on PG&E SME experience—according to which, no wire down has remained energized from a primary source. In some cases, wire down may remain energized at less than nominal voltage due to secondary sources such as induction from other circuits or phases, or it may remain energized, due to backfeed from substation transformers, but PG&E does not currently have data to determine how often this occurs.

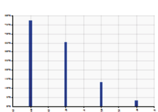
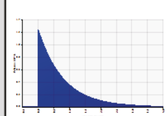
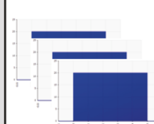
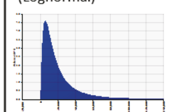
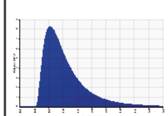
Based on the wire down data, PG&E has categorized the wire down events into eight drivers summarized below in order of highest frequency to lowest. Note that the driver numbering (D2 through D9) is based on the order of the drivers as they are listed in the model rather than the order in which they appear below.

- **D2 – Vegetation:** Tree, tree limb, or other vegetation contact with conductors that result in wire down events. Vegetation can physically bring down conductors when it falls onto conductors or it could cause faults that result in conductor failure and wire down. This driver was associated with 64 out of 279 (22.9 percent) wire down events from 2012-2016, or an average of 12.8 events per year.
- **D6 – 3rd Party (Wire Down):** Actions initiated by third parties that result in wire down events. This driver includes aircraft contacts, automobile collisions, vandalism (e.g. Gunshots), and contact with other foreign objects such as ships, balloons, cranes, etc. This driver was associated with 57 out of 279 (20.4 percent) wire down events from 2012-2016, or an average of 11.4 events per year.
- **D3 – Equipment Failure – Conductor:** Deterioration of conductor due to wear and tear that results in wire down events. This includes failures due to stressors such as vibration. This driver was associated with 53 out of 279 (19.0 percent) wire down events from 2012-2016, or an average of 10.6 events per year.
- **D5 – Equipment Failure – Other:** Failure of other line equipment such as poles, insulators, and distribution lines which result in wire down events. Includes all equipment failures not in the Equipment Failure – Conductor and Equipment Failure – Connector/Hardware driver categories. This category also includes wire down due to contamination by animal waste or dust. This driver was associated with 45 out of 279 (16.1 percent) wire down events from 2012-2016, or an average of 9.0 events per year.
- **D4 – Equipment Failure – Connector/Hardware:** Deterioration of connectors, splices, or other connecting hardware that results in wire down events. This driver was associated with 28 out of 279 (10.0 percent) wire down events from 2012-2016, or an average of 5.6 events per year.
- **D8 – Natural Forces:** Natural phenomena such as fire and lightning that can bring down PG&E assets and result in wire down events. This driver was associated with 26 out of 279 (9.3 percent) wire down events from 2012-2016, or an average of 5.2 events per year.
- **D9 – Company Initiated:** Actions initiated by PG&E workers, such as those initiated through work procedure errors, which result in wire down. This driver was associated with 4 out of 279 (1.4 percent) wire down events from 2012–2016, or an average of 0.8 events per year.
- **D7 – Animal:** Animal contacts that result in wire down. Typically, this involves animals making contact with multiple conductors of a transmission line, creating a fault between the two conductors that result in wire down. This driver was associated with 2 out of 279 (0.7 percent) wire down events from 2012-2016, or an average of 0.4 events per year.

III. **Consequences**

PG&E applies a standardized approach to measuring consequences as part of its enterprise risk program. As such, the consequences of this risk are based on six impact categories: safety, environmental, reliability, compliance, trust, and financial. For additional granularity, safety category is further divided into injuries and fatalities. Figure 10-2 below shows the range of consequences and the attributes that help describe the expected value and tail average risks and the associated Multi-Attribute Risk Score (MARS) values.

Figure 10-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	CPUC Data	CPUC Data	NA	PG&E Data	NA	PG&E Data and SME Input	PG&E and Claims Data
Consequence Distributions	Safety consequences are only on OHC that stay energized Percent of events with an injury =100% Mean=0.75 (Poisson) 	Safety consequences are only on OHC that stay energized Percent of events with a fatality=100% Mean=0.75 (Poisson) 	Covered in the wildfire risk model	Percent of OHC events with resulting in an outage=57% Ave duration of outage=805k min (Exponential) 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=6-10% Severe=2.5-6% Low=0-2.5% (Uniform) 	Restoration costs results from all OHC events: Ave=$23k Std Dev=$28k (Lognormal)  + Compensatory claims from OHC events that stay energized: Ave=$1.1M Std Dev=$0.9M (Lognormal) 
Outcome-TA-NU[1]	2.97	2.97		38,163,873		9.42%	$5,221,186
Outcome-TA-MARS[2]	0.81	81.03		95.41		47.12	3.13
						MARS Total	**227.50**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI)**: This risk focuses on injury consequences resulting from shock due to contact with energized conductor. As inputs into the TOHC risk model, PG&E is using historical injury data reported to the CPUC for the years 2012-2016. These years were used to be consistent with the wire down data used in the model. Over that time period, there have been a total of 3 injuries from 1 contact with intact conductor event, and no injuries from wire down events. Using this input, the TOHC operational risk model calculated a baseline tail average of 2.97 injuries a year for this risk, resulting in a contribution of 0.81 MARS units from this consequence category.

  Safety – Fatalities (SF): This risk focuses on fatality consequences resulting from electrocution due to contact with energized conductor. As inputs into the model, PG&E is using historical fatality data reported to the CPUC for the years 2012-2016. These years were used to be consistent with the wire down data used in the model.

Over that time period, there have been a total of three fatalities from three separate contacts with intact conductor events, and no injuries from wire down events. All fatalities were related to the unauthorized climbing of PG&E structures. Using this input, the TOHC risk model calculated a baseline tail average of 2.97 fatalities a year, resulting in a contribution of 81.03 MARS units from this consequence category.

- **Environmental (E):** Environmental consequences are measured in dollars. Environmental consequences for wire down and contact with intact events revolve around wildfire. These consequences are discussed in the Wildfire chapter and are excluded from the TOHC risk model to avoid duplication in model outputs.
- **Reliability (R)**: Reliability consequences are measured in customer outage minutes. To model reliability consequences, PG&E is using wire down outage information from the 2012-2016 wire down data. Because the TOHC risk is limited to examining two specific public safety events (third-party contact with intact conductor and wire down), outages that do not result from these safety events are not included in the model. Because redundancy is designed into the transmission system, about 57 percent of wire down events have resulted in outages over the 2012-2016 timeframe. For the wires down events that did result in outages, the average event resulted in 804,788 customer outage minutes. Using this input, the TOHC risk model calculated a baseline tail average of 38,163,873 customer outage minutes per year, resulting in a contribution of 95.41 MARS units from this consequence category.
- **Compliance (C):** Compliance consequences are measured in dollars. Compliance costs were not used in the model because regulatory fines are shareholder funded and not applicable in the RAMP analysis.
- **Trust (T)**: Events are dependent upon safety outcomes, both injury and fatality, and categorized as: low, severe, and high. This methodology was used across all risks.[5] For this risk, PG&E assumed approximately half of the impact, based on qualitative observation of the consequences of past wire down and contact with intact events. This results in a high severity bounds of 6-10 percent, severe bounds of 2.5-6 percent, and a low bound of 0-2.5 percent. Using this input, the TOHC risk model calculated a baseline tail average of 9.42 percent brand favorability reduction per year, resulting in a contribution of 47.12 MARS units from this consequence category.
- **Financial (F)**: Financial consequences are measured in dollars. To model financial consequences, PG&E is using, as inputs, wire down restoration costs and compensatory claim costs related to TOHC. Restoration cost data was collected by sampling maintenance work orders that involved broken conductor, wire down, or conductor repair. The average value of restoration costs was calculated to be $22,645 per event. Compensatory claim costs are based on two data sources. The first data source is PG&E's claims database which contains information on claims

5 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

filed with PG&E involving TOHC. This database generally includes smaller claim amounts. Industry data was also used as an input to capture larger compensatory claim amounts. The data used represents major liability losses incurred by litigation or claims on the utilities (not limited to PG&E incidents). PG&E's internal database shows 15 claims related to transmission overhead facilities, all without payment in the time period (note that some claims may still be open). The data shows four transmission overhead items between 2011 and 2016 with loss amount values. On average, these four items resulted in an average $1,125,000 self-insured retention amounts paid out by the utilities. Using these inputs, the TOHC risk model calculated a baseline tail average of $5,221,186 of financial costs per year, resulting in a contribution of 3.13 MARS units from this consequence category.

IV. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the items described in this section helps to control the frequency or consequence of one or more drivers of the TOHC risk. Table 10-1 at the end of this section summarizes the 2016 recorded costs for the controls.

- **C1 – Design, Construction, and Operation**: Includes procedures such as engineering standards, material specifications, operation manuals, etc., and the work where those procedures are implemented. This category encompasses a large number of individual controls that are in place to control the TOHC risk, including warning signage requirements, fencing, and conductor clearance requirements, all of which are designed to ensure the correct installation and operation of TOHC and associated equipment. This control reduces the exposure related to all risk drivers for this risk.
- **C2 – Anti-Climbing Guards**: PG&E installs these guards per PG&E guarding guidance documents, which are aligned with CPUC requirements.[6] These documents contain criteria for where climbing guards must be installed. In addition to those requirements, PG&E also has processes in place to evaluate the installation of additional anti-climbing guards on structures with evidence of climbing in the past. Anti-climbing guards deter the unauthorized climbing of PG&E structures by members of the public, reducing the risk of contact with intact conductor. This control reduces the exposure related to the third-party Contact with Intact Conductor driver.
- **C3 – Inspection and Maintenance**: This control represents PG&E inspection and maintenance of overhead lines. It includes visual and infrared inspections, completion of maintenance work identified through those inspections, and maintenance work identified through other work streams. This control reduces the risk exposure associated with all the drivers for this risk, e.g., clearances corrected, reducing chance of animal contact.

---

6 The guarding requirements can be found in CPUC General Order 95 Rules 51.6-B and 61.6-B.

- **C4 – Public Awareness Programs**: This control represents PG&E external communication and outreach programs designed to educate the public on the hazards associated with wire down and contact with intact conductor. These programs also include communications to educate third-party workers who may work near transmission lines of the danger of working around those lines. This control reduces the exposure related to the Third-party Contact with Intact Conductor and 3rd Party (WD) risk drivers, and directly reduces safety consequences (both injury and fatality) – members of the public who understand the hazards associated with conductors are less likely to contact conductors.
- **C5 – Aircraft Line Markers**: This control represents PG&E's installation of line markers (such as marker balls) on conductor spans to increase visibility of those spans to aircraft. PG&E also installs lighting on structures supporting the conductor to increase visibility of those structures. This control reduces the likelihood of aircraft contact into overhead lines, therefore reducing the exposure related to the Third-party Contact with Intact Conductor and 3rd Party (WD) risk drivers.
- **C6 – Animal Abatement**: This control represents PG&E's installation of equipment, such as bird and squirrel guards, on overhead lines to prevent animal contact with conductors. These devices deter animals from perching or walking on areas of line where they may come between conductors, creating a fault on a line. Reducing the likelihood of faults on lines due to animal contact reduces the likelihood of wire down. This control reduces the exposure related to the Animal risk driver.
- **C7 – Capacity Program**: This control represents PG&E's programs to monitor and control loading on lines. This control includes modelling electrical loading on lines, and constructing and upgrading lines to provide additional capacity to reliably support increased load. These programs reduce the likelihood of overloading, which can accelerate the deterioration of line equipment and eventually cause wire down events. This, in turn, results in reduction to the exposure related to the Equipment Failure – Other, Equipment Failure – Connector/Hardware, and Equipment Failure - Conductor risk drivers.
- **C8 – Restoration and Response**: This control represents PG&E's processes to respond to and restore outages, and the work where those processes are implemented. It includes procedures to make areas safe after wire down events, and the repair of those wires down. PG&E's response after a wire down event limits the potential consequences of that event, directly reducing consequences associated with safety (injury and fatality), reliability, trust, and financial impacts.
- **C9 – System Protection Program**: This control represents system protection schemes and the devices that activate when abnormalities are detected on PG&E transmission lines. Protective relaying, which can de-energize lines when faults are detected fall into this control category. System protection limits the potential consequences of wire down events, directly reducing consequences associated with safety (injury and fatality), trust, and financial impacts.
- **C10 – Vegetation Management**: This control represents PG&E programs to manage vegetation near transmission lines. It includes the annual patrol of vegetation around lines, and the work to manage vegetation (clearing, removal) identified

through those patrols. Vegetation management reduces the likelihood of vegetation contact with overhead conductor, which may lead to wire down events. This control reduces the exposure related to the Vegetation and Natural Forces risk drivers.

Two mitigations described below are categories of work performed in 2016. As discussed in later sections, these two mitigations will continue through 2022. PG&E may propose continuation beyond 2022 based on the results and lessons learned from the mitigation work.

- **M1A – Conductor/Equipment Replacement Programs (2016):** These programs were mitigations in 2016, and represent PG&E work to proactively replace conductor and equipment on PG&E lines. It includes work such as conductor replacement, targeted circuit reliability work, and insulator replacement work, where assets are replaced on circuits for reliability and lifecycle purposes. The conductor and insulator replacement portions of this mitigation will, in general, increase in scope going into 2019 (mitigations M4 and M5 discussed below), then increase further in scope through 2022 (mitigations M7 and M8 discussed below). This control reduces the exposure related to the Equipment Failure – Other, Equipment Failure - Connector/Hardware, Equipment Failure – Conductor, and Natural Forces risk drivers.
- **M2A – Right of Way Expansion (2016):** Right of way expansion was a mitigation in 2016. This mitigation represents programs to extend the rights of way around transmission overhead lines most at risk for vegetation related outages, and the clearing of vegetation within those rights of way. The vegetation related work involved in right of way expansion is typically larger in scope than general vegetation management in that it requires the removal of all trees and other vegetation within the transmission lines' right of way. In 2016, PG&E began increasing the scope of its Right of Way Expansion work. The increase in scope will continue into 2019 then increase further in scope through 2022 (as discussed below). This control reduces the exposure related to the Vegetation risk driver.

Table 10-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Design, Construction and Operation	D1-D9	TO	–	178,565
C2	Anti-Climbing Guards	D1	TO	–	297
C3	Inspection and Maintenance	D1-D9	TO	39,249	2,969
C4	Public Awareness Programs	D1, D6	TO	61	–
C5	Aircraft Line Markers	D1, D6	GRC TO	225 109	17,980
C6	Animal Abatement	D7	TO	28	1,164
C7	Capacity Program	D3-D5	TO	–	104,157
C8	Restoration and Response	SI, SF, R, T, F	TO	1,492	10,219
C9	System Protection Program	SI, SF, T, F	TO	N/A	N/A
C10	Vegetation Management	D2, D8	TO	45,473	–
M1A	Conductor/Equipment Replacement Programs (2016)	D3-D5, D8	TO	–	20,278
M2A	Right of Way Expansion (2016)	D2	TO	–	3,236
TOTAL Expense and Capital				GRC 225 TO 86,351	338,867

In addition to these controls, PG&E is also building foundational tools that will provide further controls for this risk, such as the Transmission Support Structures (TSS) tool, which will improve the process for Transmission Support Structures Loading Calculations. The aim of the TSS technology project is to centralize the data for all PG&E transmission structure assets, improve data quality, improve data access, and improve response to outages. This will enhance risk management decision-making on transmission assets.

V. Current Mitigation Plan (2017–2019)

In addition to the work listed above, PG&E is performing incremental mitigations in 2017-2019 as listed below. Much of this work consists of expansion in scope to the two existing mitigations listed in the controls section above (M1A – Conductor/Equipment Replacement Programs, M2A – Right of Way Expansion). These mitigations were chosen, in part, because of their alignment with existing asset strategy plans that were developed based on technical evaluation and subject matter expertise. These mitigations will continue to expand in scope through 2022, and potentially beyond based on the results and learnings from the mitigation work.

The mileages referenced below are approximations and may change as project plans are completed and finalized.

- **M1B – Additional Overhead Conductor Replacement (2017–2019):** This mitigation will expand PG&E's conductor replacement program, a part of the Conductor/Equipment Replacement Programs mitigation (M1A) described in the controls section of this chapter. The program is intended to improve asset life and performance by replacing conductor that is approaching end of life, is obsolete, or is poorly performing. By replacing more conductors, this mitigation further reduces the likelihood that the above factors will result in conductor failure and wire down. This mitigation will further reduce the exposure related to the Equipment Failure – Conductor (D3) as well as the Equipment Failure – Connector/Hardware (D4) drivers, since replacing conductor would also eliminate splices on the replaced line. Effectiveness of this mitigation will be measured primarily through metrics that track wire down events. This mitigation will be performed on approximate average of 7 circuit miles per year between 2017 and 2019, targeting primarily 60 kilovolt (KV) and 115 kV circuits, which data shows are more at risk of conductor failure related wire down.
- **M1C – Additional Insulator Replacement (2017–2019):** This mitigation will expand PG&E's insulator replacement program, a part of the Conductor/Equipment Replacement Programs mitigation (M1A) described in the controls section of this chapter. By expanding insulator replacements, PG&E will improve asset life and performance by replacing insulators that are obsolete, approaching end of life, or are poorly performing. By replacing more insulators, this mitigation will further reduce the likelihood that the above factors will result in insulator failure and wire down. This mitigation will further reduce the exposure related to the Equipment Failure - Other (D5) risk driver, which includes wires down due to insulator failure. Effectiveness of this mitigation will be measured primarily through metrics that track wire down events. This mitigation will be performed on an approximate average of 59 miles per year between 2017 and 2019.
- **M2B – Additional Right of Way Expansion (2017–2019):** This mitigation will increase PG&E's right of way expansion program described in mitigation M2A in the controls section of this chapter. The additional work will target the worst performing 8 percent of transmission line miles that experience 80 percent of PG&E's vegetation related outages. These targeted circuits will be prioritized in

3 tiers determined by outage activity over the previous 3 and 10 year periods. The two time periods were chosen to ensure that circuits with both a long history, as well as those with only a more recent history of vegetation related outages are addressed by the plan. The first tier covers 60 percent of the vegetation related transmission line outages and represents worst performing circuits using both the 3 and 10 year data sets. Tier 2 covers an additional 10 percent of vegetation related outage activity and is based on the last 3 years of outage data. Tier 3 covers an additional 10 percent of outage activity as define by the worst performing circuits over the last 10 years. Because a majority of vegetation issues are on this small population of lines, the work will efficiently reduce the exposure related to the Vegetation (D2) risk driver. Effectiveness of this mitigation will be measured primarily through metrics tracking wire down events. The mitigation will be performed on an approximate average of 119 circuit miles per year between 2017 and 2019.

- **M3A – Additional Public Awareness Outreach (2017–2019):** This mitigation represents an addition to PG&E's Public Awareness Programs (C4) discussed in the controls section of this chapter. This mitigation involves the creation of a new program to draft and mail out, twice per year, bill inserts that warn customers of the dangers of wire down, and to inform them of the hazards associated with performing activities around intact overhead conductor. Adding these outreach materials to the public awareness portfolio will make the general public more aware of the hazards associated with overhead conductors, which may reduce the number of contacts with energized conductors and reduce the exposure related to the Third-Party (Contact w intact) (D1) driver. The risk model assumes negligible impact to post risk event consequences, such as contact with wires down, since TOHCs are significantly less likely to remain energized during wire down events. Effectiveness of this mitigation will be measured primarily through monitoring of injury and fatality reportable incidents to the CPUC. This mitigation is shared with EO's DOCP risk, and costs are split evenly between the two risks. This mitigation will begin in 2018.

The scope of the mitigations between 2017 and 2019 are based, generally, on PG&E's ability to execute the projects contained in each mitigation plan. Most transmission line work has a multi-year duration, and work execution can fluctuate year over year as parallel projects are started and completed. Additionally, project execution may take time to ramp up, as dependencies such as design, planning and permitting limit the amount of work that can be done early in the program/project lifecycle.

Table 10-2 shows the estimated costs associated with 2017-2019 TOHC risk mitigation work.

Table 10-2: 2017 to 2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1B	Additional Overhead Conductor Replacement (2017-2019)	2017	2019 (Will lead into mitigation M1D in 2020)	D3, D4	3,721 (C) – (E)	12,667 (C) – (E)	6,977 (C) – (E)
M1C	Additional Insulator Replacement (2017-2019)	2017	2019 (Will lead into mitigation M1E in 2020)	D5	619 (C) – (E)	14,917 (C) – (E)	18,443 (C) – (E)
M2B	Additional Right of Way Expansion (2017-2019)	2017	2019 (Will lead into mitigation M2C in 2020)	D2	6,737 (C) – (E)	10,024 (C) – (E)	12,007 (C) – (E)
M3A	Additional Public Awareness Outreach (2017-2019)	2018	2019	D1	– (C) – (E)	– (C) 40 (E)	– (C) 40 (E)
TOTAL Expense and Capital by Year					11,077 (C) – (E)	37,609 (C) 40 (E)	37,426 (C) 40 (E)

VI. **Proposed Mitigation Plan (2020–2022)**

PG&E performed an evaluation of all mitigations considered and how each relates to the TOHC risk drivers. The mitigations included in the proposed plan are listed below. The mileages referenced are approximations and may change as project plans are completed and finalized.

- **M1D – Additional Overhead Conductor Replacement (2020–2022):** This mitigation represents an increase to the conductor replacement work previously described in mitigations M1A and M1B to further reduce exposure related to the Equipment Failure - Conductor (D3) and Equipment Failure – Connector/Hardware (D4) wire down drivers. It increases overhead transmission conductor replacements from an average of 7 miles per year in 2017-2019 to an approximate average of 26 miles per year in 2020-2022.
- **M1E – Additional Insulator Replacement (2020–2022):** This mitigation represents an increase to the insulator replacement work previously described in mitigations M1B and M1C to further reduce exposure to the Equipment Failure – Other (D5) wire down risk driver. It increases insulator replacements from an average of 59 miles per year in 2017-2019 to an approximate average of 139 miles per year in 2020-2022.
- **M2C – Additional Right of Way Expansion (2020–2022):** This mitigation represents an increase to the right of way expansion work previously described in mitigations

M2A and M2B to further reduce exposure related to the Vegetation (D2) risk driver. It increases right of way expansion from an average of 119 miles per year in 2017-2019 to an approximate average of 177 miles per year in 2020-2022.

- **M3B – Additional Public Awareness Outreach:** The proposed plan also includes the continuation of the Additional Public Awareness Outreach mitigation (M3A) outlined in Section IV - Current Mitigation Plan (2017 to 2019).

The proposed plan was established based on PG&E's current overall TOHC asset strategy plan. PG&E's asset strategy is informed by the risk quantification generated by the TOHC risk model, PG&E's Wildfire risk model, and additional quantification of reliability risk exposure modeled outside of RAMP. PG&E is continuing its evaluation of the model outputs and using the outputs to confirm, inform, and adjust its transmission investment strategy rather than to completely replace that strategy. As a result, not all the proposed mitigations have the highest Risk Spend Efficiencies (RSEs) per the TOHC risk model.

The proposed plan fulfills PG&E's safety, reliability improvement, and lifecycle replacement asset strategy goals in a cost effective way. Because several of these mitigations are expansions of existing work, PG&E has a good understanding of the benefits of the work, and can take advantage of existing experience to complete the work efficiently. In addition, the proposed mitigations will help to avoid an increase in PG&E's risk profile driven by increased likelihood of asset failure as assets reach "end of useful life". Much of PG&E's transmission infrastructure was constructed in the years following WWII. As such, many assets are nearing "end of useful life". As these of assets near the end of their expected useful lives, PG&E will need to increase its level of asset replacements to avoid degradation in overall customer reliability and system performance.

The Additional Right of Way Expansion (M2B) mitigation was chosen for the proposed plan because it reduces exposure to the largest driver to transmission wire down, Vegetation. This, combined with the fact that the work to clear vegetation from right of ways is not as costly as other work, such as asset replacement, means that this mitigation is more cost effective. Through right of way expansion, PG&E will also be able to reduce the frequency of its on-going right of way maintenance cycle. In turn, this reduction in right of way maintenance activity will reduce cost for PG&E's customers. PG&E was not able to reflect these cost savings in the operational risk model, which would have improved the associated RSE score for the mitigation. As discussed in mitigation M2B PG&E has observed that a small population of its lines (approximately 8 percent) is responsible for approximately 80 percent of its vegetation related wire down events. This means that the planned targeting of this mitigation to the small population of worst performing lines will have an outsized impact in reducing vegetation wire down events, making this mitigation even more cost effective. This mitigation has the second highest RSE of the six mitigations examined in the model.

The Additional Overhead Conductor Replacement (M1D) and Additional Insulator Replacement (M1E) mitigations were chosen because replacements represent a core part of any asset management program. Replacing assets that are approaching end of life expectancy, are obsolete, or are poorly performing is essential to ensuring that those assets do not fail and result in events such as the wire down risk event. PG&E is increasing the pace of its replacement programs to prevent impacts from aging infrastructure. These mitigations have low RSEs based on model outputs due to the high cost of transmission asset replacement work. PG&E plans to perform this work despite the low RSEs because of its classification as core asset strategy work. The work will continue until the impact of model limitations on mitigation RSEs can be understood. Model limitations may be under calculating additional benefits of this mitigation. Specifically, the model only calculates benefits over a short timeframe (asset replacements may provide decades of benefits), it does not model future deterioration of assets and the consequences of deferred mitigation (if this work is not performed, risk does not remain static, but may increase), and it only narrowly includes the benefits related to the risk events (replacing assets may also reduce reliability events that do not involve wire down).

The Additional Public Awareness Outreach (M3B) mitigation was primarily chosen due to its very low relative cost and its ability to reach a large number of PG&E customers. Though the model shows that the absolute risk reduced by the outreach materials is relatively low based on the assumption that a limited number of customers likely read the inserts, it does have the largest RSE of all mitigations examined in its model because the cost is much lower than any of the other mitigations. Despite this mitigation's high RSE resulting from its relatively low cost, PG&E will not be expanding the scope of the mailings (i.e., by sending out numerous mailers per year) until the impact of the inserts can be measured. PG&E suspects that benefits of the inserts will decrease by a large margin with each additional annual mailing. Going forward, PG&E will explore additional opportunities for outreach via different forms of media, which may counter the diminishing returns associated with more frequent mailings.

Table 10-3 below summarizes the mitigations' RSE and associated estimated costs for each year covered by the 2020 General Rate Case (GRC).[7]

[7] Note that though the years examined are the years included in the 2020 GRC, transmission costs are recovered through a separate Transmission Owner rate case.

Table 10-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ 1$M)	EV RSE (Units/ 1$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1D	Additional Overhead Conductor Replacement (2020-2022)	0.0052	0.0042	2020	2022 (May lead into additional mitigation past 2022)	D3, D4	21,321-23,565 (C) – (E)	29,763-32,895 (C) – (E)	35,625-39,375 (C) – (E)
M1E	Additional Insulator Replacement (2020-2022)	0.0031	0.0025	2020	2022 (May lead into additional mitigation past 2022)	D5	28,500-31,500 (C) – (E)	24,700-27,300 (C) – (E)	23,275-25,725 (C) – (E)
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	2020	2022 (May lead into additional mitigation past 2022)	D2	14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)
M3B	Additional Public Awareness Outreach (2020-2022)	6.6628	4.2298	2020	2022 (Will become a control)	D1	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)
PROPOSED PLAN TA RSE: 0.0670 TOTAL Expense and Capital by Year							64,068-70,812 (C) 38 - 42 (E)	68,238-75,420 (C) 38 - 42 (E)	71,250-78,750 (C) 38 - 42 (E)

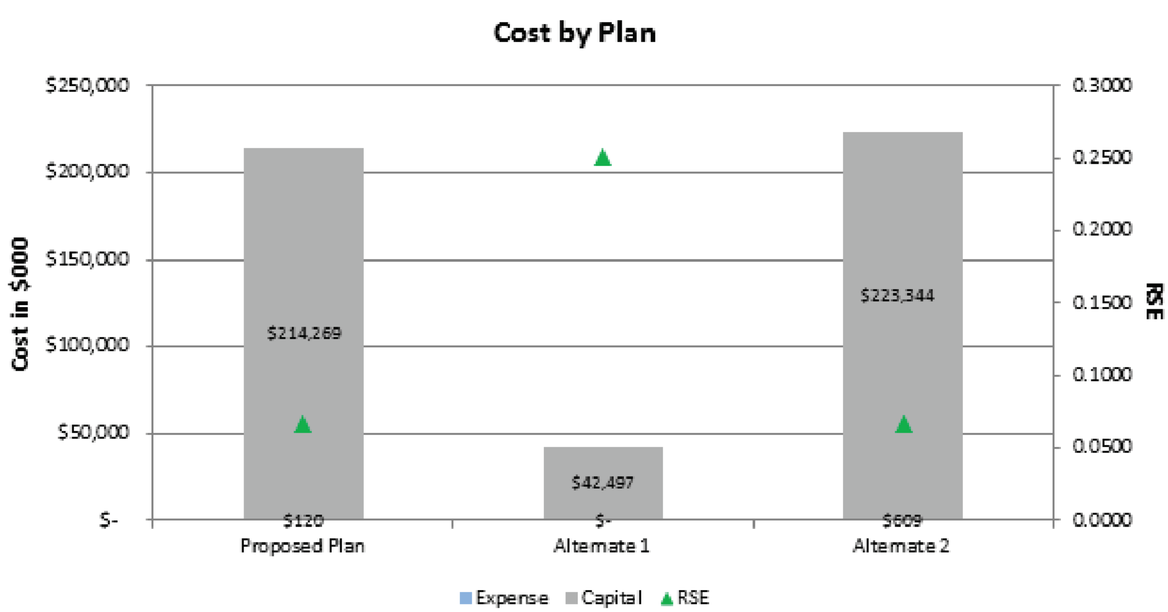
VII. **Alternatives Analysis**

After assessing all of the mitigations, PG&E has two alternative plans to the proposed mitigation plan. Alternative Plan 1 was created as a limited cost alternative. This plan was developed around the idea that PG&E would choose to perform only one of the risk mitigations examined in the model. Alternative Plan 2 was developed around the idea that PG&E would perform all of the risk mitigations examined in the model. The mitigations included in each of the alternative plans and the proposed plan are shown below in Table 10-4. Figure 4 presents the costs associated with the proposed and alternative plans.

Table 10-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M1D	Additional Overhead Conductor Replacement (2020-2022)	0.0052	0.0042	x		x	WP 10-2
M1E	Additional Insulator Replacement (2020-2022)	0.0031	0.0025	x		x	WP 10-8
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	x	x	x	WP 10-14
M3B	Additional Public Awareness Outreach	6.6628	4.2298	x		x	WP 10-20
M4	Additional Anti-Climbing Guard Installation	0.0659	0.0449			x	WP 10-26
M5	Additional Vibration Damper Installation	0.0150	0.0123			x	WP 10-32

Figure 10-3: Alternatives by Cost and RSE Score



A. **Alternative Plan 1**

This alternative proposal represents a limited cost mitigation plan. As mentioned above, this plan was developed around the idea that PG&E would limit its mitigations to only

one of the risk mitigations examined in the model. The mitigation chosen for this alternative plan was Additional Right of Way Expansion (M2C).

Additional Right of Way Expansion was chosen for the reasons outlined in the discussion of the proposed plan above. If PG&E were to limit itself to performing one mitigation over the others, this mitigation makes sense because it targets the largest risk driver, is cost effective, and has the second highest RSE. Although the Additional Public Awareness Outreach (M3B) mitigation has a larger RSE than the Additional Right of Way Expansion (M2C), additional outreach was not chosen as the sole mitigation for this limited cost plan because the model shows that in absolute terms, outreach reduces the risk by a relatively small amount.

PG&E does not plan to implement this alternative plan. Although this limited cost approach alternative involves the most effective mitigation, PG&E believes that this mitigation should not be undertaken in isolation. A more diverse mitigation portfolio would be better suited to reducing the overall risk. Performing several mitigations will allow PG&E to utilize its existing diverse resources (construction resources along with vegetation management resources) and will ensure that drivers other than Vegetation are addressed.

Table 10-5 below summarizes the RSEs for the single mitigation in Alternative Plan 1 and the associated estimated costs for each year covered by the 2020 GRC if they were to be implemented.

Table 10-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ 1$M)	EV RSE (Units/ 1$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	2020	2022 (May lead into additional mitigation past 2022)	D2	14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)
ALTERNATIVE PLAN 1 TA RSE: 0.2507 TOTAL Expense vs. Capital by Year							14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)

B. **Alternative Plan 2**

This alternative proposal represents a mitigation plan where PG&E implements all the mitigations included in the proposed plan, with an additional two mitigations: Additional Anti-Climbing Guard Installation and Additional Vibration Damper Installation. These two additional mitigations are described as:

- **M4 – Additional Anti-Climbing Guard Installation**: This mitigation represents an expansion of the criteria under which climbing guards are installed on PG&E facilities. Three out of the four TOHC public injury and fatality events that occurred from 2012 through 2016 were related to the unauthorized climbing of PG&E structures. As discussed above in the control section of this chapter, the Anti-Climbing Guards (C2) control, as currently implemented is aligned with the requirements of CPUC GO 95. However, installing additional anti-climbing guards or other types of public protection above and beyond the current requirements may further reduce the number of public safety incidents related to the unauthorized climbing of PG&E structures. If implemented, this mitigation would reduce the exposure related to the third-party (Contact w intact) (D1) driver. Effectiveness of this mitigation would be measured primarily through monitoring of injuries and fatalities constituting reportable incidents to the CPUC. This mitigation represents anti-climbing guard installations on approximately 55 miles of line per year beginning in 2020.
- **M5 – Additional Vibration Damper Installation**: This mitigation represents a program to install vibration dampers on existing conductors that did not meet damping criteria per the standards in effect when they were constructed, but that would require dampers if installed under today's more stringent damping criteria. Vibration dampers reduce wind induced conductor motion (aeolian vibration), which can cause fatigue on those conductors. This wind induced fatigue may eventually result in conductor failure and wire down. This mitigation would entail identifying conductors without dampers which would require dampers if installed today, assessing whether they require damping, then installing vibration dampers if it is determined that additional damping is necessary. Installing these additional dampers would further reduce the likelihood of wire down, reducing exposure to the Equipment Failure – Conductor (D3) risk driver. Effectiveness of this mitigation would be measured primarily through metrics that track wire down events. This mitigation represents vibration damper installations on approximately 10 miles of line per year beginning in 2020.

Though Additional Anti-Climbing Guard Installations and Additional Vibration Damper Installations have the third and fourth highest RSEs per the TOHC model, PG&E does not plan to implement this alternative mitigation plan at this time for two reasons.

First, this work is already bundled into other work streams. For example, whenever PG&E constructs or replaces conductors or line support structures, PG&E uses standards that include requirements for damping and guarding. PG&E believes that this work may be an adequate substitute to specialized guarding and damping programs. Moreover, the incremental cost of implementing damping and guarding as part of other programs is small. While bundling these activities may decrease the rate of installation, the reduction in cost associated with efficient implementation makes this approach superior to standalone installation programs.

Second, PG&E does not have an existing targeted Anti-Climbing Guard or a targeted Vibration Damper installation program. Before initiating these specialized programs, PG&E would seek to validate their benefits. Unlike the other mitigations, PG&E does

not have detailed studies on the efficacy of climbing guards, or in-depth studies on vibration caused conductor failure, so PG&E has relied upon assumptions that PG&E would need to further assess before going forward. For example, anti-climbing guard efficacy was based on studies of the efficacy of suicide barriers on bridges because PG&E currently does not have or know of a methodology to quantify the efficacy of anti-climbing guards, and PG&E intends to further evaluate use of these studies as a proxy.

Table 10-6 below summarizes the RSEs for the mitigations in Alternative Plan 2 and the associated estimated costs for each year covered by the 2020 GRC if they were to be implemented.

Table 10-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ 1$M)	EV RSE (Units/ 1$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1D	Additional Overhead Conductor Replacement (2020-2022)	0.0052	0.0042	2020	2022 (May lead into additional mitigation past 2022)	D3, D4	21,321-23,565 (C) – (E)	29,763-32,895 (C) – (E)	35,625-39,375 (C) – (E)
M1E	Additional Insulator Replacement (2020-2022)	0.0031	0.0025	2020	2022 (May lead into additional mitigation past 2022)	D5	28,500-31,500 (C) – (E)	24,700-27,300 (C) – (E)	23,275-25,725 (C) – (E)
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	2020	2022 (May lead into additional mitigation past 2022)	D2	14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)
M3B	Additional Public Awareness Outreach	6.6628	4.2298	2020	2022 (Will become a control)	D1	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)
M4	Additional Anti-Climbing Guard Installation	0.0659	0.0449	2020	2022	D1	2,874-3,176 (C) – E)	2,874-3,176 (C) –(E)	2,874-3,176 (C) – (E)
M5	Additional Vibration Damper Installation	0.0150	0.0123	2020	2022	D3	–(C) 155-171(E)	–(C) 155-171(E)	–(C) 155-171(E)
ALTERNATIVE PLAN 2 TA RSE: 0.0669 TOTAL Expense and Capital by Year							66,942-73,988 (C) 193 -213 (E)	71,112-78,596 (C) 193 -213 (E)	74,124-81,926 (C) 193 -213 (E)

VIII. Metrics

Current outcome metrics used to track the TOHC risk include the following:

- **Public Contacts:** The number of electric incidents that were reported to the CPUC involving third-party fatalities or injuries, rising to the level of inpatient hospitalization, attributable or allegedly attributable to contact with energized PG&E-owned electric transmission, substation, and distribution facilities.
- **Transmission wires down**: The number of instances where a normally energized electric transmission conductor is broken, or remains intact, and falls from its intended position to rest on the ground or a foreign object.

Proposed accountability metrics include those shown in Table 10-7 below, as well as their associated drivers and mitigations they monitor and the proposed targets to be set.

Table 10-7: Proposed Accountability Metrics

Mitigation	Associated Driver and Consequence	Proposed Metric	Targets
Additional Public Awareness Outreach	D1	Public Contacts (Transmission & Distribution)	Maximum 9 Incidents
Additional Right of Way Expansion	D2	Transmission Wires Down	Maximum 42 Wires Down
Additional Overhead Conductor Replacement	D3, D4	Transmission Wires Down	Maximum 42 Wires Down
Additional Insulator Replacement	D5	Transmission Wires Down	Maximum 42 Wires Down

IX. Next Steps

The risk quantification effort undertaken as part of the RAMP process has provided an important step toward using a data driven statistical model to compare TOHC risk investments and guide changes to PG&E's investment plan. As PG&E continues to refine risk modeling, PG&E will increase integration of model outputs into the investment planning process. It should be noted that the data, assumptions and analysis used in this chapter represent the information available at the time and is expected to change in the future for many reasons including additional or improved data availability, environmental risk factor changes and technology improvements.

As the risk model is a significant step towards quantification, and because PG&E understands the uncertainties in model outputs due to the model limitations, PG&E's transmission overhead risk mitigation plan continues to be largely based on work established by technical and subject matter expertise prior to the RAMP process. Much of the analysis used to develop the prior work plan was based on data similar to that used in the model. Where the model is helpful, however, is its ability to consolidate those mitigations into one place and provide a potential mechanism to compare those mitigations against one another using common units.

The risk model also provided some insight into the overall consequences to the risk. PG&E qualitative assumption was that this risk is primarily a reliability risk to the company, and less so a safety risk. The data gathered for the model provides quantitative support for that assumption. The safety incident data shows that fatalities on transmission lines are uncommon, and are primarily due to the unauthorized climbing of PG&E structures by members of the public, an external event that is difficult for PG&E

There are several key areas of model improvement necessary to allow PG&E to further rely on the model outputs for investment planning decisions.

First, through the modelling process, PG&E has identified significant differences in the risk profiles of the two TOHC risk events. The consequences of, and the mitigations to third-party contact with intact events are very different than those of wire down events. For example, the data used in the model shows that safety consequences are primarily the result of contact with intact events and not wire down events. Additionally, wire down event frequency can be reduced through direct mitigation such as right of way expansion and conductor replacement, whereas third-party contact with intact events are generally mitigated through indirect means such as public awareness outreach. Because of the differences between these risk events, PG&E will evaluate the impacts and value of separating the third-party contact with intact event from the wires down event.

Second, in calculating RSE, PG&E needs to be able to include benefits that are not specifically related to the risk event. At present, some RSE calculations are understating benefits for higher cost mitigations, which are inappropriately deflating the associated RSE for the mitigation. For example, Additional Overhead Conductor Replacement will reduce the frequency of outages caused by the wire down risk event, but may also reduce outages that are not associated with wire down. At present, the benefits of the mitigation that are not associated with wire down events are not included in the RSE calculation.

Third, further refinements to quantify the change in PG&E's future risk profile are warranted. At present, the model only looks at historical data and assumes a static risk

level. For many of PG&E's assets, the asymmetric distribution of asset age and health will result in an increase failure rate and degraded system performance as waves of assets reach "end of useful life". The current model does not account for this prospective increase in system risk. Further, refinement will be needed to effectively quantify the appropriate level of asset replacement required to meet risk tolerance.

Another opportunity for PG&E will be to apply RSE modeling to current controls to optimize steady state investment plans. Leveraging quantification generated by the risk model will allow additional targeting of controls to increase effectiveness where the current risk profile is largely asymmetric. The risk model may allow PG&E to maximize risk reduction by reprioritizing investments within it existing controls.

Finally, enhancements to the model's representation of mitigation cost and other economic factors would allow PG&E to fully rely on risk modeling for investment decisions and analysis of alternatives. Examples of these enhancements include capturing the full value of a given mitigation across its entire useful life, accounting for avoided cost associated with mitigation investments, and normalizing expense and capital costs across time. Adjustment in the model to transform financial components into a Net Present Value or Present Value of Revenue Requirement may allow for optimization of investment to maximize the benefits to PG&E customers.

While additional improvements will allow PG&E to fully operationalize this risk model, the work to develop this model to date has helped the company mature in the area of risk quantification. PG&E expects to build off this momentum and continue to improve its asset and risk management strategies through increasing levels of risk quantification and modeling.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 11
WILDFIRE

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 11
WILDFIRE

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Wildfire[1]
IN SCOPE	Fire ignitions and associated impacts resulting from interaction with Pacific Gas and Electric Company (PG&E) electric assets
OUT OF SCOPE	Fire ignitions and associated impacts not related to PG&E electric assets
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data and Subject Matter Expert (SME) input

Extreme weather, extended drought and shifting climate patterns have intensified the challenges associated with wildfire management in California. Environmental extremes, such as drought conditions followed by periods of wet weather, can drive additional vegetation growth (fuel) and influence both the likelihood and severity of extraordinary wildfire events.

Over the past five years, as we have seen across California, inconsistent and extreme precipitation, coupled with more hot summer days, have increased the wildfire risk and made it increasingly more difficult to manage.

The risk posed by wildfires has increased in PG&E's service area as a result of an extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases resulting from record rainfall following the drought, among other environmental factors. Other contributing factors include local land use policies and historical forestry management practices. The combined effects of extreme weather and climate change also impact this risk.

This filing has been prepared and submitted against the backdrop of extraordinary wildfires that occurred in PG&E's service area beginning on October 8, 2017. Northern California experienced strong wind gusts up to at least 79 miles per hour. These destructive winds, along with millions of trees weakened by years of drought and recent renewed vegetation growth from winter storms, all contributed to some trees, branches and debris impacting PG&E's electric lines across northern California.

PG&E has prepared this Risk Assessment and Mitigation Phase (RAMP) filing while numerous investigations associated with the October 2017 Northern California Wildfires are ongoing. PG&E's mitigation plan includes: continued roll-out of the Wildfire Reclosing Operation Program; fuel reduction and powerline corridor management; overhang clearing; and targeted conductor replacement. PG&E will review the results of the Northern California Wildfire investigations and incorporate them in future wildfire

1 Wildfire risk is defined as: PG&E assets may initiate a wildland fire that endangers the public, private property, sensitive lands, and/or leads to long duration service outages.

risk management approaches, as appropriate. PG&E expects to update the wildfire risk analysis, modeling and proposed mitigations as more information becomes available.

Based on PG&E's analysis, the main drivers for fire ignitions related to PG&E facilities are:

- Vegetation contact with conductors;
- Equipment failure; and
- Third party contact.

PG&E's controls focus on reducing the probability of wildfire ignitions overall, with particular emphasis on limiting ignitions in high-risk wildfire areas and on days when fire risk is elevated.

Managing wildfire risk is a top priority for PG&E; the annual total investment in 2016 for all wildfire risk related controls was approximately $750 million.[2] Most of this investment, about $435 million,[3] was focused on PG&E's biggest wildfire risk driver—Vegetation Management (VM). In recent years, the significant increase in wildfire controls spend has been driven by vegetation-related Catastrophic Event Memorandum Account (CEMA) work to remove trees impacted by drought and bark beetles.[4]

Through the RAMP process, PG&E evaluated its ability to reduce the wildfire risk, and concluded that VM work continues to be the most significant and effective control in reducing fire ignitions. VM work addresses the highest wildfire risk driver (37 percent of ignitions),[5] and was shown in the wildfire operational risk model to have a significantly higher Risk-Spend Efficiency (RSE) than infrastructure replacement work. PG&E plans to continue investing significant resources in VM throughout the 2017-2022 timeframe.

PG&E will continue to implement four wildfire mitigations for the 2017-2019 timeframe. The first is continuing expansion of the Wildfire Reclosing Operation Program in

---

2 This is the approximate amount shown in Table 11-1.

3 This is the approximate total of VM and CEMA VM, as shown in Table 11-1.

4 CEMA vegetation work began in 2014 and increased to about $190 million, annually, as of 2016.

5 The fire ignitions are defined based on the reportable fire ignition definition from the California Public Utilities Commission (CPUC) per Decision (D.) 12-02-015.

elevated and extreme areas, based on Fire Map 2.[6] The Wildfire Reclosing Operation Program expansion potentially reduces risk for all top drivers,[7] including: vegetation, equipment failure, third party and animal (any drivers which are associated with wire down events), by potentially avoiding an ignition during wire down events. The second mitigation is replacement of non-exempt[8] surge arresters with exempt surge arresters certified by the California Department of Forestry and Fire Protection (CAL FIRE) as low fire risk—this work will continue through 2022. The other two mitigations are further expansion of VM practices: fuel reduction and powerline corridor management; and overhang clearing.

Additionally, PG&E will perform the following mitigations in the 2020 through 2022 time frame:

- Continued expansion of Wildfire Reclosing Operation Program by adding Supervisory Control and Data Acquisition (SCADA) capabilities to existing circuit breakers and line reclosers in extreme fire risk areas (2020-2022), building on PG&E's ongoing SCADA expansion as part of its Distribution Automation Program;
- Continued fuel reduction and powerline corridor management (2018-2020);
- Continued overhang clearing (2018-2020);
- Continued replacement of non-exempt surge arresters(2017-2022); and
- Expanded targeted conductor replacement (2020-2022).

PG&E considered several alternative mitigations in its analysis beyond the five mitigations described above, including: targeted underground conversion, additional pole replacements, and other possible mitigations. Ultimately, the five proposed mitigations were chosen because they have relatively high RSEs, focus on the main risk drivers and have additional benefits, as reflected in the Distribution Overhead Conductor – Primary Risk. However, as noted above, the ongoing wildfire

6 Fire Map 2 is being developed by the Fire Safety Technical Panel, as required by Order Instituting Rulemaking (OIR) 15-05-006. Fire Map 2 is not final as of this filing, and has gone through numerous revisions. PG&E leveraged Fire Index Areas to use as the exposure for the RAMP model. In future iterations of the model, the exposure can be changed to align with Fire Map 2 elevated and extreme areas. In addition PG&E leveraged the outputs of the Ignition Spread Model, which provides a quantified risk output used to compare the relative risk reduction of performing mitigations in higher risk areas.

7 The drivers are defined in Section II.c, below.

8 Exempt equipment is certified by CAL FIRE as having low fire risk, and thus exempt from vegetation clearing requirements associated with Public Resource Code (PRC) 4292.

investigations may identify additional drivers and mitigations that will be reflected in PG&E's assessment of wildfire risk going forward.[9]

The Fire Safety Rulemaking,[10] which is currently underway, is developing a state-wide regulatory fire map, known as Fire Map 2, and new fire safety rules. PG&E will make adjustments, as necessary, to the current plans to comply with new rules stemming from the Fire Safety Rulemaking. In addition, the incremental mitigations, which are beyond compliance requirements proposed in this chapter, will be targeted in the elevated and extreme areas of Fire Map 2.

In 2018 and beyond, PG&E will continue to look for opportunities to prioritize the existing substantial investment in wildfire-related controls in ways that most effectively reduce the wildfire risk.

PG&E will continue to build on the assessment completed as part of RAMP by refining the modeling capabilities and quantification of the wildfire risk to improve identification and prioritization of work that has a significant impact on wildfire risk reduction. One area for future model enhancement is to break out transmission and distribution (T&D) circuit miles separately in the wildfire operational risk model. Exposure in the model is by circuit mile, and currently does not consider the relatively higher number of ignitions per circuit mile that occur on distribution circuits, as compared to transmission circuits. Additional areas for enhancement include modeling the RSE of select existing

---

9 One alternative, that PG&E understands may be part of future public discussions, is whether there are locations and conditions where electric facilities should be preemptively de-energized. In such a discussion, there are many important issues that would need to be addressed. Proactively de-energizing parts of the electric grid is highly complex, due to significant public safety issues such actions can pose. De-energizing lines can have an immediate and very broad impact on public safety, affecting first responders, and the operation of critical facilities, such as: hospitals; schools; the provision of water and other essential services; traffic signals; communications systems; operation of building systems, such as elevators; and much more. The many potential public safety issues associated with de-energizing lines are the same reasons electric systems must be designed to be highly reliable. Modern society relies on these systems, which are essential to public safety. Widespread de-energizing would therefore introduce additional safety risks that would have to be carefully considered, communicated and addressed across many agencies and with the communities and customers PG&E serves. Potential actions that would have to be considered range from the establishment of communications protocols to notify customers of plans to de-energize lines to working with public agencies and critical service providers to implement emergency energy systems among critical customer classes.

10 Fire Safety Rulemaking ((R.) 15-05-006).

controls and further calibration of tail outputs[11] of the model against the impacts of recent catastrophic fires that have occurred across California.

II. Risk Assessment

A. Background

PG&E defines wildfire risk as: PG&E assets may initiate a wildland fire that endangers: the public, private property, sensitive lands, and/or leads to long-duration service outages.

PG&E has designated wildfire as an enterprise risk[12] (in addition to being a top safety risk) since 2006. This risk is reviewed annually by the Safety, Nuclear and Operations, Committee of PG&E's Board of Directors. PG&E's exposure to wildfire risks continues to escalate despite increasing investment in compliance and public safety programs given various environmental and human factors. The most notable investments are the T&D routine VM work and the CEMA VM work related to the drought and the ongoing tree mortality state of emergency.[13] The CEMA work investment alone amounts to $190 million in 2016 and $208 million in 2017.[14] Environmental variations, such as drought conditions or periods of wet weather that drive additional vegetation growth and wildfire fuel increases, can influence both the likelihood and severity of a wildfire event.

PG&E used the bow tie methodology, as shown in Figure 11-1, below, to develop a quantitative risk model specific to wildfire risk (wildfire operational risk model). This model uses a combination of PG&E-specific data, industry data, and SME input, to gain a better understanding of the risk drivers for wildfire. PG&E also used an Ignition Spread Modeldeveloped by REAX Engineering described in a report for PG&E which simulates ignitions across PG&E's service territory, incorporating climatology, terrain, and fuel, in a probabilistic computer simulation, to help prioritize where to perform work which most effectively reduces the risk of catastrophic fires related to PG&E facilities.

---

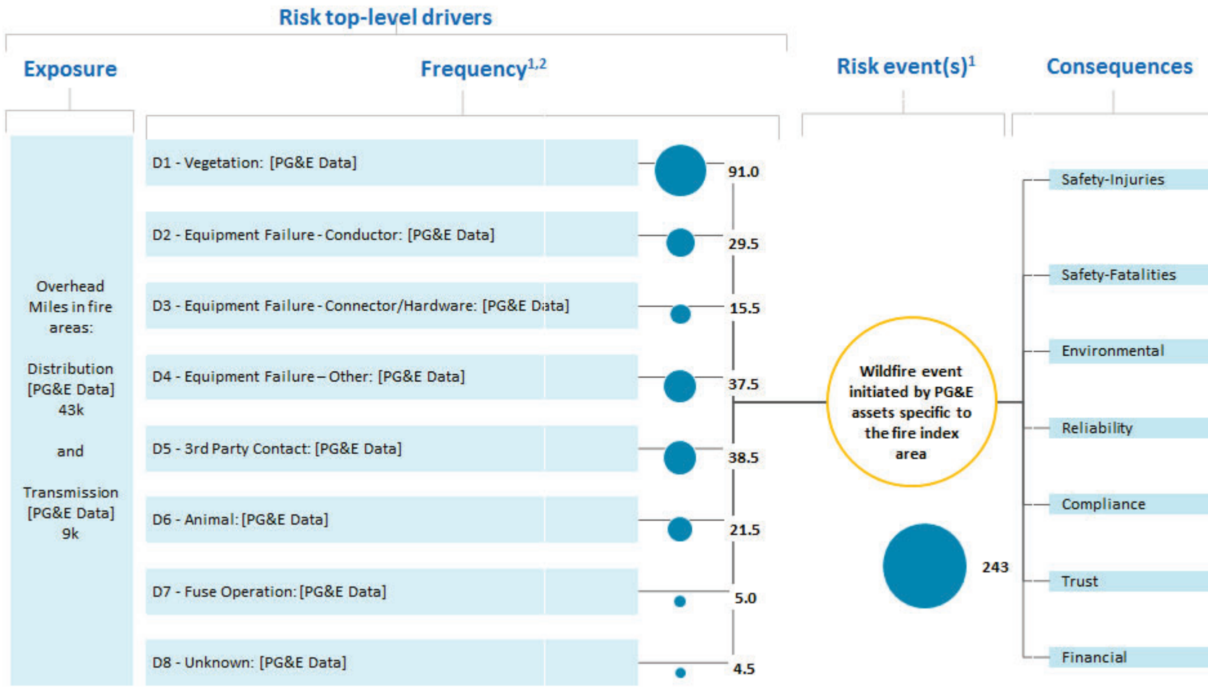
11 Tail outputs refer to the lower probability, higher consequences for each consequence category (safety, environmental, reliability, trust, financial).

12 Enterprise risk is defined in the introduction chapter.

13 Proclamation of a state of emergency declared on October 30, 2015. This proclamation states in part "State agencies, utilities, and local governments to the extent required by their existing responsibilities to protect the public health and safety, shall undertake efforts to remove dead or dying trees in these high hazard zones that threaten power lines, roads and other evacuation corridors, critical community infrastructure, and other existing structures."

14 This is the estimated 2017 forecast spend as of October 1, 2017.

Figure 11-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson distributions.

B. Exposure

PG&E has approximately 82,000 distribution overhead circuit miles and 18,000 transmission overhead circuit miles. The exposure included in the wildfire operational risk model is 43,000 overhead distribution circuit miles and 9,000 overhead transmission circuit miles, which are the total circuit miles that fall within Fire Index Areas, as determined by the Fire Danger Rating System.[15] The Fire Index Areas were created by federal and state agencies to enable an area-based fire danger rating, based on local weather conditions. The parts of PG&E service territory not fire-indexed, have significantly lower fire risk, and are excluded from the model.

Not all overhead line miles in Fire Index areas have equal risk. The probability of ignitions related to PG&E facilities varies from area to area, as do the consequences. In order to compensate for the differences in ignition probability and consequence, multipliers were applied to certain mitigations implemented in targeted areas within the total exposure area.

---

15 The area fire-indexed, as part of the Fire Danger Rating system, encompasses nearly all elevated and extreme areas, as defined by the draft Fire Map 2. After the Fire Map 2 is finalized, the wildfire operational risk model will be updated to align with it.

When a mitigation that addresses a specific risk driver is implemented in a targeted area, and a risk driver frequency per circuit mile is quantifiable, a multiplier is used to estimate the effectiveness of the proposed mitigation in reducing the targeted risk driver.[16] Using the Ignition Spread Model, described above, PG&E was able to develop a quantified estimate of the relative effectiveness of performing work in the highest risk circuit miles (estimated at 16,500 circuit miles), as compared to applying the mitigation across the entire system. This multiplier is used as part of the mitigation effectiveness estimate input in the Wildfire Operational Risk Model.

After Fire Map 2 is finalized, the Ignition Spread Model can be used to develop multipliers to quantify the relative effectiveness of performing work in the elevated versus extreme fire risk areas, which can then be used in for future wildfire risk assessments.

C. Drivers and Associated Frequency

There were 486 fire ignitions[17] associated with PG&E facilities that occurred in Fire Index areas within PG&E's service territory during the 2-year period 2015-2016. These 486 ignitions (or an average of 243 per year) were related to eight top-level risk drivers:

- **D1 – Vegetation:** Tree, tree limb, or other vegetation contact with conductors that result in fire ignition. The vegetation risk driver accounts for 37 percent[18] of 243 ignitions, or 91 per year.
- **D2 – Equipment Failure – Conductor:** Failure of conductor resulting in wire down and fire ignition. All three equipment failures categories may be influenced by weather and other environmental factors (e.g., corrosive environment). The Equipment Failure – Conductor risk driver accounts for 12 percent of 243 ignitions, or 29.5 per year.
- **D3 – Equipment Failure – Connector/Hardware:** Failure of connectors, splices, or other connecting hardware resulting in wire down and fire ignition. The equipment Failure – Connector/Hardware risk driver accounts for 6 percent of 243 ignitions, or 15.5 per year.

---

16 The workpaper for each mitigation explains the estimates and multipliers used in determining the overall effectiveness of the mitigation in reducing each risk driver and how it was derived.

17 Note the bow tie in Figure 11-1 shows the annualized risk driver frequency which is half of 486. The fire ignitions are defined, based on the reportable fire ignition definition from CPUC, per D.12-02-015. Fire ignitions used in the model are the subset that were located in fire-Indexed areas.

18 The total of all risk drivers percentages do not add up to 100 percent, due to rounding.

- **D4 – Equipment Failure – Other:** Failure of other line equipment, such as: poles, insulators, transformers, and capacitors, that leads to fire ignition. The Equipment Failure – Other risk driver accounts for 15 percent of 243 ignitions, or 37.5 per year.
- **D5 – Third Party Contact:** Contact caused by a third party, leading to fire ignition, such as cars hitting poles and Mylar balloon contacts. The Third-Party Contact risk driver accounts for 16 percent of 243 ignitions, or 38.5 per year.
- **D6 – Animal:** Animal contacts that result in fire ignition, such as birds contacting energized conductors then falling to the ground and causing an ignition. The Animal risk driver accounts for 9 percent of 243 ignitions, or 21.5 per year.
- **D7 – Fuse Operation:** Operation of a fuse for a faulted condition that results in fire ignition from the blown fuse. The Fuse Operation risk driver accounts for 2 percent of 243 ignitions, or 5 per year.
- **D8 – Unknown:** Situations where PG&E was unable to determine the cause of the ignition; however, it appeared that the ignition may have been attributable to PG&E facilities. The Unknown risk driver accounts for 2 percent of 243 ignitions, or 4.5 per year.

D. Consequences

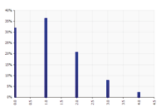
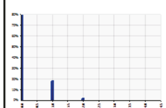
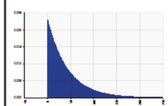
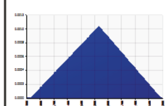
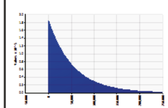
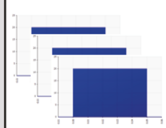
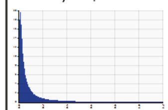
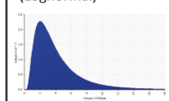
In the overwhelming majority of cases,[19] the fires are extinguished quickly, resulting in very little damage, but in some cases, larger wildfires can result. There is a range of potential public safety risks resulting from a fire ignition associated with PG&E assets. Figure 11-2 shows the range of consequences and the attributes that help describe the expected value and tail average risks and the associated Multi-Attribute Risk Score (MARS). This probabilistic modeling was created based on a CPUC requirement.[20] The data sources used for each of the consequence attributes are provided in the table. This table represents PG&E's first effort at modeling the full consequence distribution related to the wildfire risk. While this work represents a significant step, there is still work to be done to calibrate the consequence distribution using additional data sets, especially for lower probability, higher consequence events. The results of investigations into the catastrophic October 2017 Northern California Wildfires, and other wildfire events from 2017, could inform future iterations of PG&E's wildfire operational risk model, depending on the outcome of those investigations.

---

19 359 of 486 fire ignitions or 74 percent of CPUC-reportable fire ignitions in Fire Index Areas in 2015 and 2016 were less than 1/4 acre in size.

20 CPUC D.16-08-018, p. 151.

Figure 11-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	Calfire and NFIRS Data	Calfire and NFIRS Data	Calfire, PG&E & Pacific Union settlement Data	PG&E Data	NA	PG&E Data	PG&E and Claims Data
Consequence Distributions	Percent of wildfire events with an injury = 0.51% Percentage of events with injury or fatality = 0.62% Mean=1.14 (Poisson) 	Percent of wildfire events with a fatality = 0.10% Percentage of events with injury or fatality = 0.62% Mean=0.23 (Poisson) 	Ave # acres burned/wildfire event = 44 acres (exponential)  x Cost per acre: Min = $855/acre Ave = $1,865/acre Max = $2,778/acre (Triangular) 	Percentage of events resulting in outage = 95% Ave = 54k customer minutes (Exponential) 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Property: destroyed: Ave=0.392 Std Dev=1.454 Shift=0.018 (Lognormal) x Cost/property destroyed=$778k  + Compensatory claims from safety events: Ave=$4.1M Std Dev=$3.3M Shift=$66k (Lognormal) 
Outcome-TA-NU[1]	5.89	1.78	$27,649,728	14,791,813		18.5%	$125,436,835
Outcome-TA-MARS[2]	1.61	48.54	2.76	36.98		92.43	75.26
						MARS Total	**257.58**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI)**: As part of the wildfire operational risk model, PG&E estimates a ratio of five injuries for every one fatality. This assumption was based on data from the National Fire Incident Reporting System. The expected number of injuries based on the model is 1.7, the tail average is 5.89, and the corresponding MARS contribution is 1.61 MARS units.

- **Safety – Fatalities (SF)**: The model leverages CAL FIRE data[21] to determine the probability of a fire leading to a fatality. The CAL FIRE data, which includes data from state-wide events, provides a more complete distribution of low probability events, including fatalities per fire. Based on the model assumptions, the number of fatalities is 0.3, the tail average is 1.78, and the corresponding MARS contribution is 48.54 MARS units.

- **Environmental (E):** Cost per acre distribution is based on the compensatory amounts paid to the United States (U.S.) Forest Service. In addition, a distribution of the number of acres impacted per fire, based on CAL FIRE data, is also used. These two distributions are multiplied together in the model to determine the environmental cost per ignition. The U.S. Forest Service (USFS) compensatory claims are used because the costs are considered strongly-linked to environmental impacts. Other non-environmental costs are included in the Financial Impact section. The expected environmental impact, based on the model, is $23 million, the tail

21 CAL FIRE data is recorded by CAL FIRE on fires responded to and attributes of those fires.

average is $28 million and the corresponding MARS contribution is 2.76 MARS units.

- **Reliability (R)**: Measured as minutes of outage time (PG&E customer-minutes) related to fire ignitions in 2015 and 2016. Reliability is also another measure of public safety. Power outages impact a wide array of public safety systems, including: traffic lights, hospitals, police and fire stations, telecommunications systems, in-home respirators and other medical devices, water pumps, and electric garage door openers. The expected reliability impact, based on the model, is 13 million customer-minutes; the tail average is 15 million customer minutes, and the corresponding MARS contribution is 36.98 MARS units.
- **Compliance (C)**: Compliance costs were not included in the model because regulatory fines are typically shareholder-funded and therefore not applicable in the RAMP analysis.
- **Trust (T)**: Events are dependent upon safety outcomes, both injury and fatality, and categorized as: low, severe, and high. This methodology was used across all risks.[22] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on trust is approximately 18.5 percent.
- **Financial (F)**: For financial impacts, the model utilizes the preliminary costs associated with the Butte Fire[23] as a benchmark to determine the estimated cost-per-structure impacted. The total costs associated with the Butte Fire have not been finalized and will need to be updated in future analysis. The environmental costs are taken out of the total, and the remaining cost is modelled as a cost-per-structure impacted. A distribution for number of structures-impacted-per-fire is created in the model, based on CAL FIRE data. The expected financial impact, based on the model, is $84 million, the tail average is $125 million, and the corresponding MARS contribution is 75.26 MARS units.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

This section describes PG&E's existing controls for wildfire risk. The efficacy of these controls is reflected in the current performance of the risk.[24] Each of the controls described in this section manages one or more risk drivers of the Wildfire risk.

---

22 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

23 See PG&E 2017 Annual Report page 56 note 3, Third-party claims and Utility clean-up, repair, and legal costs [http://s1.q4cdn.com/880135780/files/doc_financials/2017/annual/2017-Proxy-Statement-Final.pdf].

24 Current performance of the risk is the baseline risk model outputs discussed in Section II consequences.

Table 11-1, included below, summarizes the controls and associated 2016 recorded costs associated with each control.

C1 – Overhead Patrols and Inspections: PG&E patrols and inspects its overhead electric facilities to identify damaged facilities and other conditions that may pose a risk of wildfire ignition. Patrols and inspections are performed annually, in urban and high-risk wildland interface areas, and bi-annually, in rural areas. Any corrective actions required in wildland interface areas receive priority treatment, and are scheduled and tracked to completion prior to peak fire season. Maintaining auditable documentation of patrol and inspection activity and findings is another key program feature. This control reduces exposure to all wildfire risk drivers.

C2 – Vegetation Management: PG&E has a VM Program focused on compliance with General Order (GO) 95 Rule 35, PRC 4292, and PRC 4293. The program includes specific inspection[25] and identification of potentially problematic vegetation, clearing and removal, and quality assurance. The main components of this work are the routine VM Program, Vegetation Control (VC) and quality assurance.

- The Routine Vegetation Program is designed to comply with GO 95 Rule 35, and PRC 4292 and PRC 4293[26] through annual inspection and associated tree work. In addition to routine compliance work, PG&E performs Public Safety and Reliability vegetation work, which targets areas with risk factors associated with a higher likelihood of vegetation-caused outages and vegetation-caused wires down. Moving into 2018, PG&E is building on previous VM wildfire risk reduction work. The VM work plan is being developed to focus even more on the highest risk wildfire areas, based on the extreme Fire Risk Area of Fire Map 2.[27] Further prioritizing work in the highest risk areas will continue to build upon the improvements to the effectiveness of this work in reducing the probability of catastrophic wildfires.
- The VC Program performs vegetation clearing around approximately 120,000 utility poles that have non-exempt equipment and are subject to PRC 4292[28] or local requirements.

---

25 Vegetation inspections are performed separately from the overhead patrols and inspections referred to in C1. Vegetation inspections are performed by VM contractors trained to evaluate potential vegetation interactions with power lines.

26 CPUC GO 95 Rule 35, PRC 4293 and PRC 4294 are regulatory compliance requirements for VM and clearance from vegetation to conductors.

27 Fire Map 2 proceeding (R.16-05-006). PG&E is developing draft plans using a draft version of Fire Map 2, and will update these plans as Fire Map 2 is finalized.

28 PRC 4292 requires that PG&E maintain a firebreak of at least 10 feet in each direction from the outer circumference of the base of subject poles to prevent the spread of fire.

- PG&E performs audits through the VM Quality Assurance Program throughout the year, independent of pre-inspection and tree work. These audits are designed to verify inspections and tree work performed by contractors.

This control reduces exposure to Vegetation risk driver (D1).

C3 – Catastrophic Event Memorandum Account – Vegetation Management: This control includes five initiatives intended to address the vegetation impacts associated with prolonged drought conditions and the ongoing bark beetle-related tree mortality state of emergency.[29] The five initiatives are as follows:

- Enhanced Vegetation Inspection and Mitigation – Additional ground and air inspection and tree work in high fire threat areas to provide increased assurance that changing forest conditions will not result in vegetation interactions with power lines.
- Wild Land Urban Interface Protection – Additional VM inspections and tree work in Local Responsibility Areas[30] (LRA) and providing VC work in high fire risk LRAs.
- Fuel Reduction and Emergency Response Access – Funding local Fire Safe Councils[31] to support fuel reduction in high fire danger areas around PG&E's electric distribution facilities.
- Early Detection of Forest Disease/Infection – Formed cooperative information sharing with universities, CAL FIRE and the USFS on forest health.
- Early Detection and Response to Wildfires – Funding fire lookouts, aerial patrols, and fire detection cameras located near PG&E's electric distribution facilities.

This control reduces exposure to vegetation risk driver (D1).

C4 – Non-exempt Equipment Replacement: Exempt equipment is certified by CAL FIRE as having low fire risk. This control refers to the planned replacement of equipment not exempt from PRC 4292 requirements with equipment that is exempt. This control reduces exposure to Equipment Failure – Other risk driver (D4).

---

29 The Governor proclaimed a state of emergency on tree mortality on October 30, 2015, and CPUC resolution ESRB-4, dated June 16th, 2014 directed Investor-Owned Electric Utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility facilities.

30 LRAs include incorporated cities, cultivated agriculture lands, and portions of the desert. LRA fire protection is typically provided by city fire departments, fire protection districts, counties, and by CAL FIRE under contract to local government [http://www.fire.ca.gov/fire_prevention/fire_prevention_wildland_faqs#desig01].

31 Fire Safe Councils are community-based, self-governed groups of people that focus on fire safety; they: distribute fire safety materials; teach fire-safe home construction techniques; conduct fuel reduction projects; fund defensible space projects around homes and escape routes; sponsor lookout towers; and form community safety networks, and the like.

C5 – Overhead Conductor Replacement: This control refers to programs that replace overhead conductor either proactively through a targeted program or reactively after a failure occurs. Conductor in high-risk wildfire areas and conductor with higher likelihood of failure are prioritized in the proactive replacement. This control reduces exposure primarily to the Equipment Failure – Conductor and Equipment Failure – Connector/Hardware risk drivers (D2, D3). In addition, it reduces some wire down events and associated possible fire ignition for Equipment Failure – Other, Third-Party Contact, and Animal. (D4, D5, D6).

C6 – Animal Abatement: Includes installing new equipment or retrofitting existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on T&D poles, such as jumper covers, bushing covers, perch guards, or perching platforms. This control reduces exposure to the animal risk driver (D6).

C7 – Protective Equipment: The installation of new equipment (e.g., fuses, reclosers, and SCADA installations enabling remote operation) that isolates equipment when abnormal system conditions are detected. This control reduces exposure for all wildfire risk drivers.

C8 – Overhead Equipment Replacement: Proactive identification and replacement of critical overhead distribution equipment, such as: cross-arms, transformers, capacitors, reclosers, and switches. Equipment is identified for replacement through the inspection and patrols control (C1) or through ad hoc inspection. This control reduces exposure to the equipment failure-other risk driver (D4).

C9 –Pole Replacement: This control includes the identification and replacement of wood T&D poles, including intrusive inspection work (pole test and treat), and replacement or remediation. GO 165[32] requires intrusive inspections on a 20-year cycle. PG&E’s program tests poles every 10 years for most poles[33]—exceeding the inspection cycle compliance requirements—and incorporates wood preservation practices that exceed compliance requirements. These factors allow PG&E to identify and mitigate the decay of wood to reduce failures. Additionally, there is an accelerated retirement program[34] underway, which will proactively replace additional poles in 2018 and 2019 assessed to have higher likelihood of failure prior to their next scheduled inspection. This control reduces exposure to the Equipment Failure – Other risk driver (D4).

---

32 GO 165 mandates inspection requirements for Electric Distribution and Transmission Facilities.

33 Intrusive testing for penta-treated poles under 50 years old is done every 20 years.

34 Part of the 2017 General Rate Case (GRC) Settlement Agreement was to replace additional poles in 2018 and 2019 beyond those identified by the Pole Test and Treat Program.

C10 – Wood Pole Bridging: This control refers to the installation of a bonding wire, which connects the insulator bracket through-bolt of all phases of a distribution wood pole, to reduce the probability of a pole fire occurring, due to current traveling through the wooden cross arms. Pole fires tend to occur after a light rain, likely due to increased current leakage through the insulators. This control reduces exposure to the Equipment Failure – Other risk driver (D4).

C11 – Design Standards: This control refers to general standards for proper application of equipment to ensure safe and reliable operation. For example, it includes conductor size, and conductor types in corrosion zones, or the use of specific types of connectors and splices. This control reduces exposure to all wildfire risk drivers.

C12 – Restoration, Operational Procedures and Training: This control refers to procedures contained in Utility Standard TD-1464S[35] for increased wildfire controls when a Fire Index Area has a rating of "Very High" or "Extreme."[36] A summary of Utility Standard TD-1464S is provided below:

- General readiness requirements for all employees are covered, including awareness of all laws, rules, and regulations of fire agencies having jurisdiction over areas in which they work or travel. Each crew must be equipped with well-maintained firefighting equipment.
- Fire Index ratings,[37] as determined on a daily basis during the fire season, are in effect from 8 a.m. to two hours after sunset.
- PG&E is restricted from manually energizing any section of line that experiences an outage in a Fire Index Area rated "Extreme" or "Very High," as determined by the daily Fire Index Map, until the line has been patrolled and all trouble cleared.

This control reduces exposure to all wildfire risk drivers.

Table 11-1 summarizes the controls and 2016 recorded costs associated with each control.

---

35 Utility Standard TD-1464S is the utility standard for fire danger precautions in hazardous fire areas.

36 Daily fire index ratings are determined by PG&E meteorology using the National Fire Danger Rating System (NFDRS).

37 PG&E meteorology determines the fire index rating using a high resolution weather model to drive an industry standard fire danger rating model, NFDRS, to produce fire indices required for fire danger rating. Fire danger ratings are represented as adjectives that range from low to extreme for each Fire Index Area.

Table 11-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Overhead Patrols and Inspections	All	GRC TO	19,303 1,218	–
C2	VM	D1	GRC TO	200,115 45,473	–
C3	CEMA VM	D1	CEMA	190,204	–
C4	Non-Exempt Equipment Replacement	D4	GRC	–	3,457
C5	Overhead Conductor Replacement	D2, D3, D4, D5, D6	GRC	–	31,858
C6	Animal Abatement	D6	GRC TO	1,097 28	5,476 1,164
C7	Protective Equipment	All	GRC	–	47,744
C8	Overhead Equipment Replacement	D4	GRC	20,084	77,717
C9	Deteriorated Pole Replacement	D4	GRC TO	11,503 2,461	79,874 18,819
C10	Wood Pole Bridging	D4	GRC	46	–
C11	Design Standards	All	GRC TO	n/a	n/a
C12	Restoration, Operational Procedures and Training	All	GRC TO	n/a	n/a
TOTAL Expense and Capital				**252,148 (GRC) 49,181 (TO) 190,204 (CEMA)**	**246,127 (GRC) 19,983 (TO)**

There are also four technologies which are under development which if fully implemented will provide benefits to the Wildfire risk controls described above. These technologies: (1) System Tool for Asset Risk (STAR); (2) Joint Use Map and Portal (JUMP); (3) VM Data Enablement; and (4) Next Generation Wildfire Detection are described briefly below.

STAR is a technology under development, which, when fully-implemented, will provide asset replacement direction, including Overhead Conductor Replacement (C5), Overhead Equipment Replacement (C8) and pole replacement (C9), based on asset-specific data for every piece of equipment in the three asset classes identified above. Each asset will receive a risk score that considers the probability of failure (based on asset health factors) and the resulting consequences (based on the function and location of the asset). Highest risk assets will then be prioritized for replacement.

Initial uses of STAR are focused on programs for evaluating the benefits of additional pole and conductor replacements, as well as optimization of inspection cycles based on health and risk. Future STAR uses may include addition of more electric asset classes, or

focus on different programs (e.g., VM), so that STAR can be used to target assets with the most effective programs to mitigate the risks specific to each asset.

JUMP is technology that will support the existing Pole Replacement (C9) control. Incorrect pole loading calculations, due to erroneous or missing information on attachments to poles used jointly with other utilities and third parties, could contribute to pole failures, which is a potential cause of wildfires. Unauthorized pole attachments to joint poles are particularly problematic. The JUMP technology project will streamline the sharing of pole loading data with joint tenants or joint owners, and helps prevent incorrect loading of poles used jointly with other utilities and third parties. JUMP will help ensure that PG&E meets the requirements of CPUC pole and conduit (Order Instituting Investigation/OIR) in providing pole and conduit information.

VM Data Enablement is a technology that will support and enhance the existing VM control (C1). Overhead lines are presently inspected at least annually by inspectors driving and walking the lines. The Electric VM Department has acquired remote sensing data (e.g., Light Detection and Ranging (LiDAR),[38] video, orthoimagery, etc.) in recent years to improve T&D routine maintenance, inspection, reliability and wildfire mitigation activities, by providing more accurate baseline data to enable Managers to see how vegetation interacts with other risk factors, such as asset health and failure probability. This ability to see the convergence of multiple risk drivers holds promise for enhancing PG&E's operational risk models.

The Next Generation Wildfire Detection Technology Project directly impacts the detection and response wildfire strategies. Currently, PG&E manually gathers fire ignition reports from disparate sources. Reports of new fires and subsequent mitigating actions can be delayed, depending on remoteness and the time it takes to manually gather and disseminate intelligence. The National Oceanic and Atmospheric Administration and the National Aeronautics and Space Administration recently launched the next generation of satellites via the Geostationary Operational Environmental Satellite (GOES) Program, which will significantly improve fire detection timeliness and resolution. This system will provide extremely timely fire ignition data. This technology project will integrate existing PG&E meteorology systems to deploy a wildfire detection and alerting system utilizing the new GOES data.

IV. Current Mitigation Plan (2017-2019)

PG&E's plan includes: continuation of the Wildfire Reclosing Operation Program, fuel reduction and powerline corridor management, overhang clearing, and targeted

---

38 LiDAR is a surveying method that measures distance to a target by illuminating that target with a pulsed laser light, and measuring the reflected pulses with a sensor.

conductor replacement. As described above, PG&E may make further changes to its current and proposed mitigation plans as more is learned about the causes of the wildfires and how the electric system risks should be evaluated and mitigated going forward.

M1 – Wildfire Reclosing Operation Program (SCADA programming): In the 2017 fire season, PG&E piloted its Wildfire Reclosing Operation Program on 38 select circuit breakers and line reclosers in high-risk wildfire areas. The procedure disables the reclosing operation of circuit breakers and line reclosers during "Very High" and "Extreme" fire risk weather conditions. The 38 locations were selected because they were in the high fire risk areas designated by the Fire Map 1,[39] and the equipment already had SCADA remote control capabilities installed. Disabling reclosing has both the potential to reduce the risk of fire ignition during a wire down event and a negative impact on reliability and the other associated public safety benefits described earlier in this chapter. When reclosing is disabled, a PG&E employee must be dispatched to patrol the line and determine if sustained damage has occurred prior to reclosing protective devices. Reclosing is disabled on days that are rated "Very High" or "Extreme" in a particular Fire Index Area utilizing the Fire Danger Rating System. During the 2017 fire season, PG&E monitored the impacts of disabling reclosing to better understand the wildfire risk reduction that might be achieved, and the public safety and reliability impacts to test the efficacy of the program. PG&E's plan has been, and continues to be, the expansion of the Wildfire Reclosing Operation Program to include additional SCADA enabled reclosers and circuit breakers that are within Fire Map 2 extreme and elevated areas.

In addition to the planned expansion of the Wildfire Reclosing Operation Program, PG&E looks forward to a multi-party discussion about locations and conditions under which PG&E should preemptively shut off power to reduce wildfire risk without jeopardizing public safety and reliability. As part of these discussions, it will be important to consider the implications of preemptively initiating potentially large power outages. Large power outages impact a wide array of critical public safety systems, including: traffic lights, hospitals, police and fire stations, mobile phone systems, wi-fi networks, in-home respirators and other medical devices, water pumps, and electric garage door openers. Given these public safety risks, PG&E will engage with communities and other stakeholders to assess the full societal impact of preemptively shutting off power under high-fire risk conditions.

39 Fire Map 1 is the interim map adopted in D. 16-05-036. This map was the most relevant fire risk map available when target locations were determined in 2016.

M3 – Fuel Reduction and Powerline Corridor Management: The Fuel Reduction and Powerline Corridor Management mitigation reduces vegetation near targeted portions of overhead distribution lines. This clearing is expected to reduce the frequency and impact of ignitions caused by the vegetation risk driver. This mitigation targets approximately 3,600 miles of line for work over a five year period (2018-2022). The 3,600 circuit miles represent all of the draft Fire Map 2 extreme area.[40] The effectiveness of this work depends heavily on property owner agreements necessary to perform the work. In addition, it should be noted that as part of the Transmission Overhead Conductor risk, one of the proposed mitigations is also Additional Right of Way Expansion. This mitigation also reduces vegetation-caused outages on transmission overhead conductor; however, the impact on the wildfire risk overall is relatively small, as the transmission-caused vegetation ignitions are rare, based on historical PG&E ignition data.[41]

M4 – Overhang Clearing:[42] The Overhang clearing mitigation involves clearing vegetation above the overhead electrical distribution lines to reduce the chances of a branch falling on the line. The mitigation includes approximately 24,000 miles of overhang clearing over a five year period in high wildfire risk areas from 2018 and 2022. The 24,000 circuit miles represent all of the draft Fire Map 2 elevated and extreme areas.

M5 – Non-Exempt Surge Arrester Replacement Program: This mitigation started in 2017 and is expected to continue through 2022. This program increases the use of exempt equipment as described in PG&E's existing exempt, fire safe equipment Control C4. This program will replace non-exempt surge arresters, with exempt surge arresters which have been certified by CAL FIRE as low fire risk.

Additionally, while performing the surge arrester replacement, a previously identified grounding issue also will be corrected.[43] Replacing the surge arresters at the same time as correcting the grounding issue helps reduce wildfire risk and reduces ongoing

---

40 The draft Fire Map 2 area as of July 31, 2017 has approximately 3,600 Tier III (extreme) distribution circuit miles and 20,500 Tier II (elevated) distribution circuit miles.

41 The 2015 and 2016 PG&E fire ignition data used for RAMP does not include any transmission related vegetation cause ignitions.

42 This Overhanging Clearing mitigation, defined in the wildfire risk, is the same as the Overhang Clearing mitigation defined in the Distribution Overhead Conductor – Primary (DOCP) risk, and is proposed as a mitigation in both risks in order to show the RSE for both risks.

43 The Surge Arrester Program described in PG&E's 2017 GRC was a maintenance program intended to correct the grounding issue only that did not provide any wildfire risk reduction benefit.

maintenance costs associated with maintaining fire breaks that are no longer required once the surge arresters are replaced.

In total, this program will replace approximately 90 percent of non-exempt surge arresters throughout the system, or approximately 90,000 surge arresters, between 2017 and 2022. Half of these locations are in Fire Index areas and provide wildfire risk reduction which is reflected in the wildfire operational risk model. The costs modeled to determine the RSE are based on the investment to replace the surge arresters in Fire Index areas less the total cost to correct the grounding issues at those locations.

Table 11-2: 2017 to 2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1	Wildfire Reclosing Operation Program[(a)]	2017	2019	D1, D2, D3, D4, D5, D6		800 (E) 50 (C)	200 (E)-
M3	Fuel Reduction and Powerline Corridor Management	2018	2019	D1	-	7,986 (E)	7,986 (E)
M4	Overhang Clearing	2018	2019	D1	-	17,280 (E)	17,280 (E)
M5	Non-Exempt Surge Arrester Replacement[(b)]	2017	2019	D4	7,520 (C)	41,824 (C)	43,192 (C)
TOTAL Expense and Capital by Year					**- (E) 7,520 (C)**	**25,466 (E) 41,824 (C)**	**25,266 (E) 43,192 (C)**

____

(a) Approximately $50,000 in overhead expenses were incurred in 2016 for SCADA programming and standard revision to enable this program which was in place for the 2017 fire season.

(b) Costs associated with the Non-Exempt Surge Arrester Replacement are shown in Table 11-2, Table 11-3, Table 11-5, and Table 11-6 is the total cost of the Non-Exempt Surge Arrester Replacement Program. The cost used in the wildfire operational model was adjusted to include only incremental equipment replacement costs in the Fire Index Areas. See related mitigation workpaper for further details.

V. Proposed Mitigation Plan (2020-2022)

The RAMP analysis and subsequent 2020-2022 mitigation planning largely was completed prior to the unprecedented October 2017 Northern California wildfires. Similar to the current mitigation plan described in Section IV above, PG&E may change its proposed mitigation plan as more is learned about the causes of the wildfires and how the wildfire risk should be evaluated and mitigated going forward.

To develop its proposed mitigation plan, PG&E evaluated the RSE for a number of mitigations and took into consideration other factors such as addressing top risk drivers and capability to drive down the highest risk ignitions. PG&E also will be evaluating the actual risk reduction effectiveness of each mitigation included in the proposed mitigation plan, post-implementation, to validate its effectiveness and to inform future plans. In some cases, PG&E may decide to expand those mitigations that show the most promise for risk reduction, or implement new mitigations as more is learned.

In anticipation of risk reduction from the current plan, PG&E's proposed mitigation plan includes a continued expansion of the Wildfire Recloser Operation Program, the non-exempt surge arrester replacement, overhang reduction, and fuel reduction and powerline corridor management mitigations included in the 2017-2019 current mitigation plan. These mitigations are expected to help PG&E reduce the frequency of wildfire events related to all three of the equipment failure risk drivers and the vegetation risk driver, which together represent the biggest opportunities for overall wildfire risk reduction.

M2 – Wildfire Reclosing Operation Program (SCADA Capability Upgrades): This mitigation installs SCADA capabilities for reclosers in Fire Map 2 extreme areas.[44] This entails installation of SCADA on more than 100 reclosers per year from 2020 through 2022, building on PG&E's existing programs adding SCADA capabilities to existing circuit breakers and line reclosers as part of its Distribution Automation Program. After SCADA capabilities are added to the reclosers they will become part of the Wildfire Reclosing Operation Program. PG&E needs to further assess the equipment at applicable locations to determine if other upgrades are needed to allow for remote reclosing disablement. As required these costs will be updated and included in PG&E's 2020 General Rate Case (GRC) filing.

M3 – Fuel Reduction and Powerline Corridor Management: This mitigation is a continuation of the current mitigation as described in Section IV.

M4 – Overhang Clearing:[45] This mitigation is a continuation of the current mitigation as described in Section IV.

---

44 The estimated reclosers and circuit breakers are based on the draft Fire Map 2 area as of July 31, 2017. The Fire Map 2 area will change prior to being finalized and plans will be adjusted accordingly to reclosers and breakers in elevated and extreme areas.

45 This Overhanging Clearing mitigation defined in the wildfire risk is the same as the Overhang Clearing mitigation defined in the DOCP risk and is a proposed mitigation in both risks in order to show the RSE for both risks.

M5 – Non-Exempt Surge Arrester Replacement: This mitigation is a continuation of the current mitigation as described in Section IV. Replace 17,232 non-exempt surge arresters with exempt surge arresters each year from 2020 through 2022, resulting in replacement approximately 90 percent of all exempt surge arresters[46] in the distribution system.

M7 – Targeted Conductor Replacement (WF): This mitigation includes an additional 190 circuit miles of conductor replacement per year for 2020 through 2022 as part of a Targeted Conductor Replacement. This mitigation replaces select spans of overhead conductor in high-risk wildfire areas with hybrid tree wire (or covered conductor).

Table 11-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE	EV RSE	Start Date	End Date	Associated Drivers #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	2020	2022	D1, D2, D3, D4, D5, D6	1,995 - 2,205 (C) n/a (E)	1,995 - 2,205 (C) n/a (E)	1,995 - 2,205 (C) n/a (E)
M3	Fuel Reduction and Powerline Corridor Management[47]	0.9496	0.7977	2020	2022	D1	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)
M4	Overhang Clearing	0.3762	0.3160	2020	2022	D1	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)
M5	Non-Exempt Surge Arrester Replacement	0.0470	0.0388	2020	2022	D4	42,374 – 46,835 (C)	43,760 – 48,366 (C)	45,191 – 49,948 (C)
M7	Targeted Conductor Replacement (WF)	0.0049	0.0041	2020	2022	D2, D3, D4, D6	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)
TOTAL PROPOSED PLAN RSE: 0.0965 **TOTAL Expense and Capital by Year**							**234,977 - 259,712 (C) 20,213 – 30,319 (E)**	**236,363 - 261,243 (C) 20,213 – 30,319 (E)**	**237,794 - 262,825 (C) 20,213 – 30,319 (E)**

VI. Alternatives Analysis

PG&E performed an assessment of the following mitigations considered for inclusion in the proposed plan and how each relates to the risk drivers of wildfire:

- **M2 – Wildfire Reclosing Operation Program**: This is the mitigation as described in Section V.

46 The percentage of surge arresters is an estimate based on SME judgement. The remaining approximately 10 percent are surge arresters installed on poles that do not have a distribution transformer.

47 M3, M4 and M7 mitigations are listed without escalation. In the 2020 GRC values will be adjusted to include escalation.

- **M3 – Fuel Reduction and Powerline Management**: This is the mitigation, as described in Section IV.
- **M4 – Overhang Clearing**: This is the mitigation as described in Section IV.
- **M5 – Non-Exempt Surge Arrester Replacement**: This is the mitigation, as described in Section IV.
- **M6 - Targeted Underground Conversion**: The targeted underground conversion mitigation replaces overhead conductor, and hence removing any opportunity for fire ignition with electrical overhead equipment on circuit miles. This mitigation is targeted in areas with high vegetation outages in high-risk wildfire areas based on Fire Map 2. However, the RSE is relatively small due to the high cost of underground conversion. This mitigation evaluated 50 circuit miles of targeted underground conversion per year from 2020-2022.
- **M7 – Targeted Conductor Replacement (WF)**: This is the mitigation as described in Section V.
- **M8 – Avian Mitigation for Wildfire Risk**: The Avian Mitigation for wildfire risk performs avian mitigation upgrades to structures near the location of an avian contact if the location is within the designated high-risk wildfire area. This includes jumper covers, bushing covers, perch guards, or perching platforms on high-risk poles.
- **M9 – Targeted Pole Replacement**: Targeted pole replacement reviews poles which are at higher risk of failure, performs a loading assessment and replaces poles if they do not meeting the loading criteria. Replacement will reduce the probability of failure and associated possible fire ignition. This mitigation replaces additional poles per year than the existing pole replacement program control from 2020-2022.

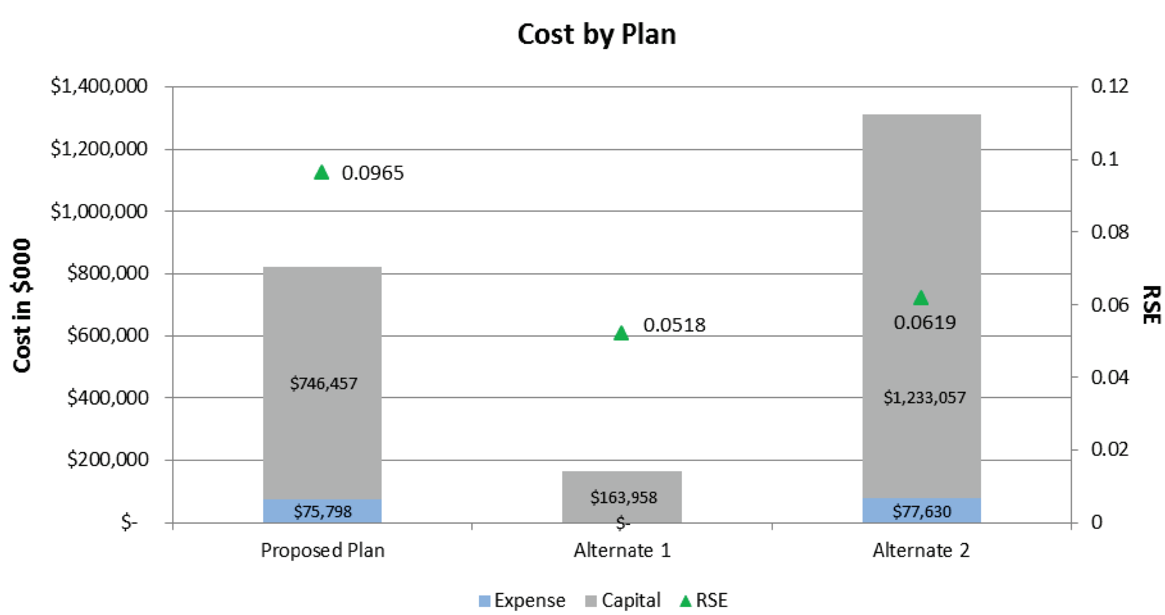
PG&E looked at key factors that ensure public safety, reliability, and drive down risk on the system. The Alternative 1 Plan does not go far enough for supporting public safety and reliability, while reducing risk on the system. The Alternative Plan 2 does not address the major risks, while providing a cost-effective solution for PG&E's customers. PG&E's proposed plan strikes the right balance, delivering safe and reliable service, while reducing system risk by focusing on the highest risk drivers and unnecessary costs to customers.

Table 11-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	X	X	X	WP 11-2
M3	Fuel Reduction and Powerline Corridor Management	0.9496	0.7977	X		X	WP 11-7
M4	Overhang Clearing	0.3762	0.3160	X		X	WP 11-10
M5	Non-Exempt Surge Arrester Replacement	0.0470	0.0388	X	X	X	WP 11-13
M6	Targeted Underground Conversion	0.0058	0.0048			X	WP 11-17
M7	Targeted Conductor Replacement	0.0049	0.0041	X		X	WP 11-21
M8	Avian Mitigation for Wildfire Risk	0.0016	0.0013			X	WP 11-25
M9	Targeted Pole Replacement	0.0002	0.0002			X	WP 11-28

Figure 11-3, below, shows the breakdown of the proposed plan, Alternative Plan 1, and Alternative Plan 2 based on cost and RSE.

Figure 11-3: Alternative Plans by Cost and RSE Score



A. **Alternative Plan 1**

The Alternative 1 Plan does not go far enough in supporting public safety and reliability while reducing risk on the system.

Table 11-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	2020	2022	D1, D2, D3, D4, D5, D6	1,995 – 2,205 (C)	1,995 – 2,205 (C)	1,995 – 2,205 (C)
M5	Non-Exempt Surge Arrester Replacemen t	0.0470	0.0388	2020	2022	D4	42,374 – 46,835 (C)	43,760 – 48,366 (C)	45,191 – 49,948 (C)
TOTAL ALTERNATIVE PLAN 1 RSE: 0.0518 **TOTAL Expense and Capital by Year**							**44,369 – 49,040 (C)**	**45,755 – 50,571 (C)**	**47,186 – 52,153 (C)**

B. Alternative Plan 2

The Alternative Plan 2 does not address the major risks while providing a cost-effective solution for PG&E's customers.

Table 11-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	2020	2022	D1, D2, D3, D4, D5, D6	1,995 – 2,205 (C) n/a (E)	1,995–- 2,205 (C) n/a (E)	1,995 – 2,205(C) n/a (E)
M3	Fuel Reduction and Powerline Corridor Management	0.9496	0.7977	2020	2022	D1	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)
M4	Overhang Clearing	0.3762	0.3160	2020	2022	D1	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)
M5	Non-Exempt Surge Arrester Replacement	0.0470	0.0388	2020	2022	D4	42,374 – 46,835 (C)	43,760 – 48,366 (C)	45,191 – 49,948 (C)
M6	Targeted Underground Conversion	0.0058	0.0048	2020	2022	D1, D2, D3, D4, D5, D6, D7, D8	142,500 – 157,500(C) n/a (E)	142,500 – 157,500(C) n/a (E)	142,500 – 157,500(C) n/a (E)
M7	Targeted Conductor Replacement	0.0049	0.0041	2020	2022	D2, D3, D4, D6	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)
M8	Avian Mitigation for Wildfire Risk	0.0016	0.0013	2020	2022	D6	2,090 – 2,310 (C) 570 - 630 (E)	2,090 – 2,310 (C) 570 - 630 (E)	2,090 – 2,310 (C) 570 - 630 (E)
M9	Targeted Pole Replacement	0.0002	0.0002	2020	2022	D4	9,500 – 10,500 (C) n/a (E)	9,500 – 10,500 (C) n/a (E)	9,500 – 10,500 (C) n/a (E)
TOTAL ALTERNATIVE PLAN 2 RSE: 0.0619 **TOTAL Expense and Capital by Year**							**389,067 – 430,022 (C) 24,583 - 27,170 (E)**	**390,453 – 431,553 (C) 25,583 - 27,170 E)**	**391,884 – 433,135 (C) 25,583 - 27,170 (E)**

VII. Metrics

Current metrics used to track the Wildfire risk include the following:

Fire Ignitions: A reportable fire incident includes all of the following: (1) Ignition is associated with PG&E powerlines; (2) something other than PG&E facilities burned; and (3) the resulting fire traveled more than one meter from the ignition point.

Transmission and Distribution Wires Down: This metric tracks the number of instances where an electric primary distribution or transmission conductor is broken and falls from its intended position to rest on the ground or a foreign object.

911 Calls Responded to Within 60 Minutes: This metric measures the percentage of time that PG&E personnel respond (are on site) within 60 minutes after receiving a 911 call, with onsite defined as arriving at the premises where the 911 agency personnel are waiting. The presence of PG&E first responders is critical to enable safe fire response. PG&E's response rate benchmarks as best in class compared to other participating utilities in the country.

Proposed accountability metrics include the following, related to the proposed mitigations and drivers mitigated:

Table 11-7: Metrics

Mitigation	Associated Driver #	Proposed Metric	Targets
Non-Exempt Surge Arrester Replacement	D4	Exempt Surge Arresters Installed per year	17,000 per year in 2020 through 2022
Wildfire Reclosing Operation Program	D1, D2, D3, D4, D5, D6	Recloser SCADA installations in high-risk wildfire areas	More than 100 reclosers per year in 2020 through 2022
Fuel Reduction and Powerline Corridor Management	D1	Miles of work performed in target areas	720 miles per year in 2020 through 2022
Overhang Clearing	D1	Miles of work performed in target areas	4,800 miles per year in 2020 through 2022
Targeted Conductor Replacement	D2, D3, D4, D6	Miles of conductor replaced in target areas	190 miles per year in 2020 through 2022

PG&E will continue to evaluate and adjust the metrics used to track the wildfire risk to improve risk reduction monitoring capabilities.

VIII. Next Steps

In order to maintain the safety of the communities we serve, managing wildfire risk is a top priority for PG&E. It is paramount that PG&E maintains the appropriate investments in order to reduce the wildfire risk exposure to the public and PG&E's workforce. As mentioned earlier in this filing, PG&E will incorporate the analysis of the October 2017

Northern California Wildfires, and update mitigations as needed. In order to best serve PG&E's customers, PG&E will leverage the wildfire operational risk model and Fire Map 2 to improve the effectiveness of the existing $750 million[48] annual wildfire-related safety investments. In addition the mitigations planned for 2018-2022 will further reduce wildfire risk by performing essential vegetation and infrastructure work in the highest risk areas and targeting key risk drivers.

PG&E will continue to build on the work completed as part of RAMP by refining the modeling capabilities and quantification of wildfire risk to improve identification and prioritization of work that has a significant impact on wildfire risk reduction. It should be noted that the data, assumptions and analysis used in this chapter represent the information available at the time the model was developed and mitigations were selected.

One specific area for future enhancement is to break out T&D circuit miles separately. Exposure in the model is by circuit mile, and does not consider the increased number of ignitions, which occur per-distribution-circuit-mile, compared to transmission.

Additional areas for continued model development and risk quantification include modeling the RSE of select existing controls. Another future model enhancement is to further calibrate the tail-end outputs of the model against actual impacts of the 2017 Northern California Wildfires and other high impact fires that have occurred across California in recent years.

As discussed in the alternatives section, PG&E will monitor the implementation of the existing control plan and refine assumptions about wildfire reduction effectiveness, as appropriate, to determine how to most-effectively implement the proposed mitigation plan.

PG&E is determined to learn more: as additional and improved data becomes available; as technology improves; and as energy companies, regulators and legislators understand more about how climate change and extreme weather, and other environmental factors, affect the long-term resiliency of PG&E's critical infrastructure.

---

48 This is the approximate amount shown in Table 11-1, which is the 2016 actual spend.